2. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 85 percent of total emissions on a carbon equivalent basis in 1998. This included 99, 34, and 18 percent of the nation's carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 80 percent of national emissions from all sources on a carbon equivalent basis, while the non-CO_2 emissions from energy represented a much smaller portion of total national emissions (4 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 2-1). Due to the relative importance of fossil fuel combustion-related CO_2 emissions, they are considered separately from other emissions. Fossil fuel combustion also emits CH_4 and N_2O, as well as criteria pollutants such as nitrogen oxides (NO_x), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs). Mobile fossil fuel combustion was the second largest source of N_2O emissions in the United States, and overall energy-related activities were collectively the largest source of criteria pollutant emissions.

Figure 2-1: 1998 Energy Chapter GHG Sources

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of CH_4 from natural gas systems, petroleum systems, and coal mining. Smaller quantities of CO_2, CO, NMVOCs, and NO_x are also emitted.

The combustion of biomass and biomass-based fuels also emits greenhouse gases. Carbon dioxide emissions from these activities, however, are not included in national emissions totals in the Energy chapter because biomass fuels are of biogenic origin. It is assumed that the carbon released when biomass is consumed is recycled as U.S. forests and crops regenerate, causing no net addition of CO_2 to the atmosphere. The net impacts of land-use and forestry activities on the carbon cycle are accounted for in the Land-use change and Forestry chapter. Emissions of other greenhouse gases from the combustion of biomass and biomass based fuels are included in national totals under stationary and mobile combustion.

Overall, emissions from energy-related activities have increased from 1990 to 1998 due, in part, to the strong performance of the U.S. economy. Over this period, the U.S. Gross Domestic Product (GDP) grew approximately 23 percent, or at an average annual rate of 3.1 percent. This robust economic activity increased the demand for fossil fuels, with an associated increase in greenhouse gas emissions. Table 2-1 summarizes emissions for the Energy chapter in units of million metric tons of carbon equivalents (MMTCE), while unweighted gas emissions in Teragrams (Tg) are provided in Table 2-2. Overall, emissions due to energy-related activities were 1,554.6 MMTCE in 1998, an increase of 10 percent since 1990.

Table 2-1: Emissions from Energy (MMTCE)

Gas/Source	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
CO_2	**1,322.6**	**1,308.6**	**1,332.8**	**1,365.2**	**1,385.7**	**1,396.6**	**1,445.8**	**1,464.9**	**1,472.1**
Fossil Fuel Combustion	1,320.1	1,305.8	1,330.1	1,361.5	1,382.0	1,392.0	1,441.3	1,460.7	1,468.2
Natural Gas Flaring	2.5	2.8	2.8	3.7	3.8	4.7	4.5	4.2	3.9
Biomass-Wood*	55.6	56.2	59.0	58.8	61.4	64.2	66.1	62.9	64.2
International Bunker Fuels*	32.2	32.7	30.0	27.2	26.7	27.5	27.9	29.9	31.3
Biomass-Ethanol*	1.6	1.2	1.5	1.7	1.8	2.0	1.4	1.8	2.0
Fossil Fuel Carbon in Products*	(69.4)	(69.0)	(70.7)	(73.5)	(78.4)	(79.2)	(80.7)	(84.3)	(85.6)
CH_4	**68.1**	**67.4**	**66.9**	**64.5**	**64.2**	**64.8**	**63.9**	**63.0**	**61.2**
Natural Gas Systems	33.0	33.4	33.9	34.6	34.3	34.0	34.6	34.1	33.6
Coal Mining	24.0	22.8	22.0	19.2	19.4	20.3	18.9	18.8	17.8
Petroleum Systems	7.4	7.5	7.2	6.9	6.7	6.7	6.5	6.5	6.3

Stationary Combustion	2.2	2.3	2.4	2.3	2.3	2.4	2.5	2.2	2.2
Mobile Combustion	1.5	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.3
International Bunker Fuels*	+	+	+	+	+	+	+	+	+
N_2O	**17.5**	**18.2**	**19.4**	**20.3**	**20.9**	**21.3**	**21.5**	**21.3**	**21.3**
Mobile Combustion	13.8	14.6	15.7	16.5	17.1	17.4	17.5	17.3	17.2
Stationary Combustion	3.7	3.6	3.7	3.8	3.8	3.9	4.0	4.0	4.1
International Bunker Fuels*	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.3	0.3
Total	**1,408.2**	**1,394.3**	**1,419.2**	**1,450.0**	**1,470.9**	**1,482.8**	**1,531.3**	**1,549.3**	**1,554.6**

+ Does not exceed 0.05 MMTCE
* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

Table 2-2: Emissions from Energy (Tg)

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998
CO_2	**4,849.6**	**4,798.2**	**4,887.1**	**5,005.8**	**5,081.0**	**5,121.0**	**5,301.4**	**5,371.4**	**5,397.7**
Fossil Fuel Combustion	4,840.5	4,787.9	4,876.9	4,992.1	5,067.2	5,103.8	5,284.9	5,355.9	5,383.5
Natural Gas Flaring	9.1	10.3	10.2	13.7	13.8	17.2	16.5	15.5	14.2
Biomass-Wood*	203.8	205.9	216.5	215.4	225.3	235.2	162.5	230.5	235.6
International Bunker Fuels*	118.0	120.0	110.0	99.9	98.0	101.0	102.2	109.8	114.7
Biomass-Ethanol*	5.7	4.5	5.5	6.1	6.7	7.2	5.1	6.7	7.3
Fossil Fuel Carbon in Products*	(254.5)	(253.2)	(259.1)	(269.4)	(287.4)	(290.6)	(295.9)	(309.0)	(313.8)
CH_4	**11.9**	**11.8**	**11.7**	**11.3**	**11.2**	**11.3**	**11.2**	**11.0**	**10.7**
Natural Gas Systems	5.8	5.8	5.9	6.0	6.0	5.9	6.0	6.0	5.9
Coal Mining	4.2	4.0	3.8	3.4	3.4	3.6	3.3	3.3	3.1
Stationary Combustion	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Petroleum Systems	1.3	1.3	1.3	1.2	1.2	1.2	1.1	1.1	1.1
Mobile Combustion	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2
International Bunker Fuels*	+	+	+	+	+	+	+	+	+
N_2O	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**
Mobile Combustion	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Stationary Combustion	+	+	+	+	+	+	+	+	+
International Bunker Fuels*	+	+	+	+	+	+	+	+	+

+ Does not exceed 0.05 Tg
* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

Carbon Dioxide Emissions from Fossil Fuel Combustion

Carbon dioxide emissions from fossil fuel combustion grew by 0.5 percent from 1997 to 1998. Exceptionally mild winter conditions in 1998 moderated growth in CO_2 emissions from fossil fuel combustion below what would have been expected given the strength of the economy and continued low fuel prices. Overall, CO_2 emissions from fossil fuel combustion have increased by 11.2 percent since 1990.

Eighty-five percent of the energy consumed in the United States was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 2-2 and Figure 2-3). Of the remaining portion, 8 percent was supplied by nuclear electric power and 7 percent by renewable energy (EIA 1999a).

Figure 2-2: 1998 U.S. Energy Consumption by Energy Source

Figure 2-3: U.S. Energy Consumption (Quadrillion Btu)

As fossil fuels are combusted, the carbon stored in the fuels is emitted as CO_2 and smaller amounts of other gases, including methane (CH_4), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs). These other gases are emitted as a by-product of incomplete fuel combustion.[1]

The amount of carbon in fuels varies significantly by fuel type. For example, coal contains the highest amount of carbon per unit of useful energy. Petroleum has roughly 75 percent of the carbon per unit of energy as coal, and natural gas has only about 55 percent.[2] Petroleum supplied the largest share of U.S. energy demands, accounting for an average of 39 percent of total energy consumption over the period of 1990 through 1998. Natural gas and coal followed in order of importance, accounting for an average of 24 and 22 percent of total consumption, respectively. Most petroleum was consumed in the transportation end-use sector, while the vast majority of coal was used by electric utilities, with natural gas consumed largely in the industrial and residential end-use sectors (see Figure 2-4) (EIA 1999a).

Figure 2-4: 1998 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 1.3 percent from 1990 to 1998. The major factor behind this trend was a robust domestic economy, combined with relatively low energy prices (see Figure 2-5). For example, petroleum prices reached historic lows in 1998, with prices in many cases less than those seen in the 1970s before the oil crisis. After 1990, when CO_2 emissions from fossil fuel combustion were 1,320.1 MMTCE (4,840.5 Tg), there was a slight decline of emissions in 1991 due to a national economic downturn, followed by an increase to 1,468.2 MMTCE (5,383.5 Tg) in 1998 (see Figure 2-5, Table 2-3, and Table 2-4).

Figure 2-5: Fossil Fuel Production Prices

Table 2-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (MMTCE)

Fuel/Sector	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
Coal	**480.9**	**475.2**	**477.5**	**493.9**	**495.2**	**498.1**	**520.5**	**534.5**	**539.6**
Residential	1.6	1.4	1.5	1.5	1.4	1.4	1.4	1.5	1.5
Commercial	2.4	2.2	2.2	2.2	2.1	2.1	2.1	2.2	2.2
Industrial	67.7	64.1	61.8	61.4	61.9	61.4	59.2	58.7	58.4
Transportation	+	+	+	+	+	+	+	+	+
Electric Utilities	409.0	407.2	411.8	428.7	429.5	433.0	457.5	471.8	477.3
U.S. Territories	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3
Natural Gas	**272.8**	**277.7**	**286.0**	**296.4**	**301.4**	**313.6**	**319.2**	**318.8**	**309.7**
Residential	65.1	67.5	69.4	73.4	71.7	71.7	77.5	73.7	66.3
Commercial	38.8	40.4	41.5	43.1	42.9	44.8	46.7	47.6	44.9
Industrial	117.9	119.7	125.6	131.1	132.6	139.5	144.2	142.8	139.9
Transportation	9.8	8.9	8.8	9.3	10.2	10.4	10.6	11.2	10.8
Electric Utilities	41.2	41.1	40.7	39.5	44.0	47.2	40.3	43.6	47.8
U.S. Territories	-	-	-	-	-	-	-	-	-
Petroleum	**566.4**	**552.9**	**566.5**	**571.1**	**585.4**	**580.3**	**601.7**	**607.3**	**618.9**
Residential	23.9	24.4	24.8	26.2	25.3	25.7	27.2	27.0	27.0
Commercial	18.0	17.1	16.1	14.9	14.9	15.0	14.6	13.8	13.8

[1] See the sections entitled Stationary Combustion and Mobile Combustion for information on non-CO_2 gas emissions from fossil fuel combustion.

[2] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

Industrial	100.0	94.2	104.2	98.0	102.0	97.5	103.3	105.8	101.8
Transportation	389.1	381.9	391.6	399.2	411.5	416.7	430.5	431.6	438.8
Electric Utilities	26.4	24.9	20.2	22.3	20.5	13.9	15.3	17.5	24.8
U.S. Territories	9.0	10.5	9.6	10.5	11.2	11.5	10.8	11.7	12.8
Geothermal*	**0.1**	**0.1**	**0.1**	**0.1**	+	+	+	+	+
Total	**1,320.1**	**1,305.8**	**1,330.1**	**1,361.5**	**1,382.0**	**1,392.0**	**1,441.3**	**1,460.7**	**1,468.2**

- Not applicable
+ Does not exceed 0.05 MMTCE
* Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

Table 2-4: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg)

Fuel/Sector	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
Coal	**1,763.3**	**1,742.3**	**1,750.9**	**1,811.1**	**1,815.7**	**1,826.2**	**1,908.3**	**1,959.9**	**1,978.7**
Residential	5.8	5.3	5.4	5.3	5.2	5.1	5.2	5.5	5.4
Commercial	8.7	8.0	8.1	8.1	7.8	7.6	7.8	8.2	8.1
Industrial	248.4	235.0	226.6	225.1	227.1	225.0	217.0	215.3	214.0
Transportation	+	+	+	+	+	+	+	+	+
Electric Utilities	1,499.7	1,493.2	1,510.0	1,571.7	1,574.7	1,587.5	1,677.4	1,730.0	1,750.2
U.S. Territories	0.6	0.7	0.8	0.9	0.9	0.9	0.9	1.0	1.0
Natural Gas	**1,000.3**	**1,018.1**	**1,048.6**	**1,086.7**	**1,105.0**	**1,149.7**	**1,170.4**	**1,168.9**	**1,135.4**
Residential	238.5	247.3	254.5	269.1	262.9	263.0	284.2	270.2	243.1
Commercial	142.4	148.2	152.3	158.2	157.2	164.3	171.2	174.5	164.5
Industrial	432.2	439.0	460.4	480.6	486.3	511.4	528.6	523.6	512.9
Transportation	36.0	32.8	32.1	33.9	37.2	38.1	38.7	41.0	39.6
Electric Utilities	151.1	150.6	149.3	144.9	161.4	173.0	147.7	159.7	175.3
U.S. Territories	-	-	-	-	-	-	-	-	-
Petroleum	**2,076.7**	**2,027.4**	**2,077.2**	**2,094.1**	**2,146.4**	**2,127.8**	**2,206.1**	**2,226.9**	**2,269.2**
Residential	87.7	89.4	90.9	96.1	92.8	94.4	99.7	98.9	99.1
Commercial	66.1	62.6	59.1	54.7	54.7	54.9	53.6	50.8	50.5
Industrial	366.5	345.5	382.1	359.5	373.8	357.4	378.9	387.8	373.2
Transportation	1,426.5	1,400.2	1,436.0	1,463.7	1,508.9	1,527.8	1,578.4	1,582.4	1,608.9
Electric Utilities	96.8	91.2	73.9	81.8	75.0	51.0	56.0	64.1	90.8
U.S. Territories	33.1	38.6	35.2	38.3	41.1	42.3	39.5	42.9	46.9
Geothermal*	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**	+	**0.1**	**0.1**
Total	**4,840.5**	**4,787.9**	**4,876.9**	**4,992.1**	**5,067.2**	**5,103.8**	**5,284.9**	**5,355.9**	**5,383.5**

- Not applicable
+ Does not exceed 0.05 Tg
* Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

Since 1990, overall fossil fuel consumption increased significantly. Higher coal consumption during the period accounted for about 36 percent of the change in total CO_2 emissions from fossil fuel combustion, petroleum accounted for 42 percent, and natural gas for 21 percent.

In regard to annual changes from 1997 to 1998, absolute emissions from petroleum and coal increased by 11.5 and 5.1 MMTCE, respectively. Increased demand for transportation fuels and by electric utilities were the primary causes of the growth in emissions from petroleum combustion, while record electricity demand drove most of the increase in emissions from coal combustion. Emissions from natural gas combustion, however, decreased by 9.1 MMTCE (2.9 percent), again due in large part to the mild winter conditions and lower heating demands.

An analysis was performed by the EIA (1999c) to examine the effects of weather conditions on U.S. fuel consumption patterns. The analysis—using the EIA's Short-Term Forecasting System—found that if normal weather conditions had existed in 1998, overall CO_2 emissions from fossil fuel combustion would have increased by about

1.2 percent above weather-adjusted emissions in 1997, instead of the actual 0.5 percent increase.[3] See also Box 2-1 and Table 2-11 for additional discussion on overall emission trends and Figure 2-9 for data on heating degree days.[4]

For the purpose of international reporting the IPCC (IPCC/UNEP/OECD/IEA 1997) requires that particular adjustments be made to national fuel consumption statistics. Certain fossil fuel-based products are used for manufacturing plastics, asphalt, or lubricants. A portion of the carbon consumed for these non-energy products can be sequestered for long periods of time. To account for the fact that the carbon in these fuels ends up in products instead of being combusted (i.e., oxidized and released into the atmosphere), the fraction of fossil fuel-based carbon in manufactured products is subtracted from emission estimates. The IPCC (1997) also requires that CO_2 emissions from the consumption of fossil fuels for aviation and marine international transport activities (i.e., international bunker fuels) be reported separately, and not included in national emission totals. Both estimates of carbon in products and international bunker fuel emissions for the United States are provided in Table 2-5 and Table 2-6.

Table 2-5: Fossil Fuel Carbon in Products and CO_2 Emissions from International Bunker Fuel Combustion (MMTCE)

Category/Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998
Fossil Fuel Carbon in Products	**69.4**	**69.0**	**70.7**	**73.5**	**78.4**	**79.2**	**80.7**	**84.3**	**85.6**
Industrial	67.5	67.2	68.9	71.6	76.5	77.4	78.7	82.2	83.3
Transportation	1.8	1.6	1.6	1.7	1.7	1.7	1.6	1.7	1.8
Territories	0.2	0.3	0.1	0.2	0.2	0.2	0.3	0.4	0.4
International Bunker Fuels*	**32.2**	**32.7**	**30.0**	**27.2**	**26.7**	**27.5**	**27.9**	**29.9**	**31.3**
Aviation*	12.7	12.7	12.9	13.0	13.2	13.9	14.2	15.2	15.5
Marine*	19.4	20.0	17.1	14.3	13.6	13.6	13.7	14.7	15.8

* See International Bunker Fuels for additional detail.
Note: Totals may not sum due to independent rounding.

Table 2-6: Fossil Fuel Carbon in Products and CO_2 Emissions from International Bunker Fuel Combustion (Tg CO_2)

Category/Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998
Fossil Fuel Carbon in Products	**254.5**	**253.2**	**259.1**	**269.4**	**287.4**	**290.6**	**295.9**	**309.0**	**313.8**
Industrial	247.3	246.4	252.6	262.6	280.4	283.6	288.6	301.3	305.5
Transportation	6.5	5.8	6.0	6.1	6.3	6.2	6.0	6.4	6.7
Territories	0.7	0.9	0.5	0.7	0.6	0.7	1.2	1.4	1.6
International Bunker Fuels*	**118.0**	**120.0**	**110.0**	**99.9**	**98.0**	**101.0**	**102.2**	**109.8**	**114.7**
Aviation*	46.7	46.7	47.1	47.6	48.3	51.1	52.1	55.9	56.9
Marine*	71.2	73.3	62.8	52.3	49.7	49.9	50.1	53.9	57.8

* See International Bunker Fuels for additional detail.
Note: Totals may not sum due to independent rounding.

End-Use Sector Consumption

When analyzing CO_2 emissions from fossil fuel combustion, four end-use sectors were defined: industrial, transportation, residential, and commercial. Electric utilities also emit CO_2; however, these emissions occur as they combust fossil fuels to provide electricity to one of the four end-use sectors. For the discussion below, electric utility emissions have been distributed to each end-use sector based upon their share of national electricity consumption.

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[3] The 1.2 percent growth rate in EIA's weather adjusted model is actually the average annual growth rate between 1990 and 1998. The EIA goes on to state that given the high rate of economic growth in 1998, the increase in weather adjusted emissions between 1997 and 1998 would likely have been even greater.

[4] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F, while cooling degree days are deviations of the mean daily temperature above 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1961 through 1990.

This method of distributing emissions assumes that each sector consumes electricity from an equally carbon-intensive electricity source. In reality, sources of electricity vary widely in carbon intensity. By giving equal carbon-intensity weight to each sector's electricity consumption, for example, emissions attributed to the industrial end-use sector may be overestimated, while emissions attributed to the residential end-use sector may be underestimated. After the end-use sectors are discussed, emissions from electric utilities are addressed separately. Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. Table 2-7 and Figure 2-6 summarize CO_2 emissions from direct fossil fuel combustion and pro-rated emissions from electricity consumption by end-use sector.

Table 2-7: CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector (MMTCE)*

End-Use Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998
Industrial	**451.7**	**440.3**	**458.0**	**458.0**	**466.2**	**464.4**	**477.3**	**482.5**	**478.9**
Combustion	285.6	278.1	291.6	290.5	296.5	298.3	306.7	307.3	300.0
Electricity	166.2	162.2	166.4	167.5	169.7	166.0	170.6	175.3	178.9
Transportation	**399.6**	**391.5**	**401.1**	**409.1**	**422.3**	**427.7**	**441.7**	**443.4**	**450.3**
Combustion	398.9	390.8	400.4	408.5	421.7	427.1	441.1	442.7	449.6
Electricity	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Residential	**252.9**	**257.0**	**255.8**	**271.6**	**268.2**	**269.8**	**285.4**	**284.7**	**286.8**
Combustion	90.6	93.3	95.7	101.0	98.4	98.8	106.1	102.2	94.8
Electricity	162.4	163.7	160.1	170.5	169.8	170.9	179.3	182.6	192.0
Commercial	**206.7**	**206.3**	**205.4**	**212.0**	**213.8**	**218.3**	**225.9**	**238.0**	**239.3**
Combustion	59.2	59.7	59.9	60.2	59.9	61.9	63.4	63.7	60.9
Electricity	147.4	146.7	145.5	151.8	153.9	156.4	162.5	174.4	178.4
U.S. Territories	**9.2**	**10.7**	**9.8**	**10.7**	**11.5**	**11.8**	**11.0**	**12.0**	**13.0**
Total	**1,320.1**	**1,305.8**	**1,330.1**	**1,361.5**	**1,382.0**	**1,392.0**	**1,441.3**	**1,460.7**	**1,468.2**

* Emissions from fossil fuel combustion by electric utilities are allocated based on electricity consumption by each end-use sector.
Note: Totals may not sum due to independent rounding.

Figure 2-6: 1998 End-Use Sector Emissions of CO_2 from Fossil Fuel Combustion

The overall demand for energy in the United States and other countries fluctuates in response to general economic conditions, energy prices, and weather. For example, a year with strong economic growth, low energy prices, and mild summer and winter weather conditions would be expected to have proportionally greater emissions from fossil fuel combustion than a year with poor economic performance, high energy prices, and severe average temperatures. Except for 1991, economic growth in the United States during the 1990s has fluctuated but overall been robust, and energy prices have been low and declining. Average U.S. temperatures, however have fluctuated more significantly, with hotter summer temperatures in 1998 stimulating electricity demand and warmer winter temperatures reducing demand for heating fuels.

Longer-term changes in energy consumption patterns are a function of variables that affect the scale of consumption (e.g., population, number of cars, and size of houses) and the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and consumer behavior (e.g., bicycling or tele-commuting to work instead of driving).

Carbon dioxide emissions, however, are also a function of the type fuel combusted and its carbon intensity. Producing heat or electricity using natural gas or wind energy instead of coal, for example, can reduce or even eliminate the CO_2 emissions associated with energy consumption (see Box 2-1).

Industrial End-Use Sector

The industrial end-use sector accounted for approximately one-third of CO_2 emissions from fossil fuel combustion. On average, nearly 63 percent of these emissions resulted from the direct consumption of fossil fuels in order to meet industrial demand for steam and process heat. The remaining 37 percent resulted from their consumption of electricity for uses such as motors, electric furnaces, ovens, and lighting.

The industrial end-use sector includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy consumption is manufacturing, which was estimated in 1994 to have accounted for 80 percent of industrial energy consumption (EIA 1997). Therefore, in general emissions from the industrial end-use are fairly correlated with economic growth, however, certain activities within the sector, such as heating of industrial buildings and agriculture, are also affected by weather conditions.

According to current EIA sectoral definitions, the industrial sector also includes emissions from nonutility generators (e.g., independent power producers) who produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market. The number and quantity of electricity generated by nonutilities has increased significantly as many states have begun deregulating their electricity markets. In future inventories, these nonutility generators will be removed from the industrial sector and incorporated into a single sector with electric utilities.

Although the largest share of emissions was attributed to the industrial end-use sector, from 1990 to 1998, its emissions grew the least in percentage terms (6 percent). From 1997 to 1998, emissions actually declined slightly (1 percent), likely due in part to lower output by some energy intensive industries—such as primary metals—and weather-related changes in agricultural activities.

The industry was also the largest user of fossil fuels for non-energy applications. Fossil fuels can be used for producing products such as fertilizers, plastics, asphalt, or lubricants that can sequester or store carbon for long periods of time. Asphalt used in road construction, for example, stores carbon essentially indefinitely. Similarly, fossil fuels used in the manufacture of materials like plastics can also store carbon, if the material is not burned. The amount of carbon contained in industrial products made from fossil fuels rose 24 percent between 1990 and 1998, to 85.6 MMTCE (313.8 Tg CO_2).

Transportation End-Use Sector

Transportation was second to the industrial end-use sector in terms of U.S. CO_2 emissions from fossil fuel combustion, accounting for slightly over 30 percent—excluding international bunker fuels. Almost all of the energy consumed in this end-use sector came from petroleum-based products, with nearly two-thirds due to gasoline consumption in automobiles and other highway vehicles. Other uses, including diesel fuel for the trucking industry and jet fuel for aircraft, accounted for the remainder.

Following the overall trend in U.S. energy consumption, fossil fuel combustion for transportation grew steadily after declining in 1991, resulting in an increase in CO_2 emissions of 33 percent from 1990 to 454.9 MMTCE (1,668.0 Tg) in 1998. This increase was primarily the result of greater motor gasoline and jet fuel consumption. It was slightly offset by decreases in the consumption of residual fuel.

Overall, motor vehicle fuel efficiency stabilized in the 1990s after increasing steadily since 1977 (EIA 1999a). This trend was due, in part, to a decline in gasoline prices and new motor vehicle sales being increasingly dominated by less fuel-efficient light-duty trucks and sport-utility vehicles (see Figure 2-7 and Figure 2-8). Moreover, declining petroleum prices during the 1990s, combined with a strong economy and a growing population, were largely responsible for an overall increase in vehicle miles traveled (EIA 1999a).

Figure 2-7: Motor Gasoline Retail Prices (Real)

Figure 2-8: Motor Vehicle Fuel Efficiency

Table 2-8 below provides a detailed breakdown of CO_2 emissions by fuel category and vehicle type for the transportation end-use sector. Fifty-eight percent of the emissions from this end-use sector were the result of the combustion of motor gasoline in passenger cars and light-duty trucks. Diesel highway vehicles and jet aircraft were also significant contributors, each accounting for 14 percent of CO_2 emissions from the transportation end-use sector.

Table 2-8: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (MMTCE)

Fuel/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998
Motor Gasoline	**260.6**	**259.2**	**263.1**	**269.0**	**273.3**	**278.9**	**284.1**	**286.5**	**294.6**
Passenger Cars	167.1	165.8	169.8	171.2	170.2	172.9	176.4	177.9	182.9
Light-Duty Trucks	74.8	74.6	74.5	77.7	84.1	85.7	87.4	88.1	90.6
Other Trucks	11.3	11.2	11.2	11.7	10.4	10.9	11.1	11.0	11.4
Motorcycles	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
Buses	0.6	0.6	0.6	0.7	0.9	0.8	0.6	0.6	0.6
Construction Equipment	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Agricultural Machinery	1.2	1.2	1.2	2.0	2.1	2.2	2.1	2.2	2.3
Boats (Recreational)	4.6	4.7	4.7	4.6	4.5	5.3	5.4	5.5	5.6
Distillate Fuel Oil (Diesel)	**75.7**	**72.6**	**75.3**	**77.3**	**82.5**	**83.8**	**89.8**	**93.5**	**94.0**
Passenger Cars	1.9	1.9	2.0	2.0	2.0	2.0	2.1	2.2	2.1
Light-Duty Trucks	2.4	2.4	2.4	2.6	2.8	3.0	3.6	3.9	3.9
Other Trucks	44.8	42.9	44.5	47.2	51.4	52.4	56.5	58.9	58.8
Buses	2.1	2.2	2.2	2.3	2.3	2.7	2.4	2.5	2.5
Construction Equipment	2.9	2.8	2.9	2.9	2.9	2.8	3.0	3.0	3.0
Agricultural Machinery	6.3	6.2	6.3	6.3	6.3	6.2	6.5	6.7	6.7
Boats (Freight)	4.9	4.8	5.0	4.6	4.5	4.3	5.0	5.0	5.0
Locomotives	7.2	6.6	7.2	6.5	7.8	7.9	8.6	8.8	8.8
Marine Bunkers	3.1	2.9	2.9	2.9	2.4	2.5	2.2	2.5	3.1
Jet Fuel	**60.1**	**58.1**	**57.6**	**58.1**	**60.4**	**60.0**	**62.7**	**63.3**	**64.2**
General Aviation	1.7	1.5	1.3	1.1	1.2	1.4	1.6	1.7	1.7
Commercial Air Carriers	32.2	29.8	30.6	31.3	32.0	33.1	34.1	35.3	35.8
Military Vehicles	9.8	9.7	7.5	7.2	6.2	5.8	5.4	4.8	5.0
Aviation Bunkers	12.7	12.7	12.9	13.0	13.2	13.9	14.2	15.2	15.5
Other*	3.6	4.3	5.3	5.5	7.8	5.6	7.4	6.3	6.2
Aviation Gasoline	**0.8**	**0.8**	**0.8**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
General Aviation	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7
Residual Fuel Oil	**21.9**	**22.0**	**23.0**	**19.4**	**19.1**	**18.5**	**19.2**	**15.5**	**14.5**
Boats (Freight)	5.6	4.9	8.8	8.1	7.9	7.4	7.7	3.2	1.9
Marine Bunkers	16.4	17.1	14.3	11.4	11.2	11.1	11.4	12.2	12.7
Natural Gas	**9.8**	**8.9**	**8.8**	**9.3**	**10.2**	**10.4**	**10.6**	**11.2**	**10.8**
Passenger Cars	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+
Buses	+	+	+	+	+	+	+	+	+
Pipeline	9.8	8.9	8.8	9.2	10.1	10.4	10.5	11.1	10.7
LPG	**0.4**	**0.3**	**0.3**	**0.3**	**0.5**	**0.5**	**0.3**	**0.2**	**0.2**
Light-Duty Trucks	0.1	0.1	0.1	0.1	0.2	0.3	0.1	0.1	0.1
Other Trucks	0.2	0.2	0.2	0.2	0.3	0.3	0.1	0.1	0.1
Buses	+	+	+	+	+	+	+	+	+
Electricity	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Buses	+	+	+	+	+	+	+	+	+
Locomotives	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Pipeline	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Lubricants	**1.8**	**1.6**	**1.6**	**1.6**	**1.7**	**1.7**	**1.6**	**1.7**	**1.8**
Total (including bunkers)	**431.9**	**424.4**	**431.2**	**436.5**	**449.2**	**455.4**	**469.7**	**473.5**	**481.6**

Note: Totals may not sum due to independent rounding. Estimates include emissions from the combustion of both aviation and marine international bunker fuels.

* Including but not limited to fuel blended with heating oils and fuel used for chartered aircraft flights.

+ Does not exceed 0.05 MMTCE

Residential and Commercial End-Use Sectors

From 1990 to 1998, the residential and commercial end-use sectors, on average, accounted for 20 and 16 percent, respectively, of CO_2 emissions from fossil fuel combustion. Both end-use sectors were heavily reliant on electricity for meeting energy needs, with about two-thirds of their emissions attributable to electricity consumption for lighting, air conditioning, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both the residential and commercial end-use sectors.

Unlike in other major end-use sectors, emissions from residences and commercial buildings did not decline during the economic downturn in 1991, but instead decreased in 1994, then grew steadily through 1998. This difference in overall trends compared to other end-use sectors is because energy consumption in residences and commercial buildings is affected proportionately more by the weather than by prevailing economic conditions. Both end-use sectors are also affected by population and regional migration trends.

In 1998, winter conditions in the United States were extremely warm, with heating degree days 12 percent below normal (see Table 2-8). Due primarily to these warm winter conditions, emissions from natural gas consumption in residences and commercial establishments declined by an impressive 10 and 6 percent, respectively.

Figure 2-9: Heating Degree Days[5]

In 1998, electricity consumption in the residential and commercial end-use sectors increased by 4.5 and 1.7 percent, respectively. These increases were partly the result of air conditioning related demand and the hotter than normal summer in 1998, with cooling degree days 12 percent above normal (see Figure 2-10). U.S. temperatures during June, July, and August of 1998 were on average 10 percent higher than normal levels.[6] In the month of June, alone, residential customers increased their consumption of electricity by 17 percent above that for the same period the previous year (EIA 1999b).

Figure 2-10: Cooling Degree Days

Electric Utilities

The United States relied on electricity to meet a significant portion of its energy requirements. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for uses such as lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 2-11).

Figure 2-11: Electric Utility Retail Sales by End-Use Sector

In 1998, retail sales by electric utilities increased in all end-use sectors due largely to robust economic growth and the year's summer weather conditions. The summer of 1998 for the United States was exceptionally warm, with heating degree days 14 percent above normal (see Figure 2-9).[7] As a result, in part, of increased demand for electricity, especially for air conditioning, emissions from electric utilities rose by 3.2 percent from 1997 to 1998.

To generate the majority of this electricity, utilities combusted fossil fuels, especially coal. In 1998, electric utilities were the largest producers of CO_2 emissions from fossil fuel combustion, accounting for 37 percent. Electric utilities were responsible for such a large share of emissions partly because they rely on more carbon intensive coal for a

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[5] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1961 through 1990.

[6] Measured in terms of cooling degree days. Normals defined by the average between 1961 and 1990.

[7] Heating degree days in 1998 were approximately 3 standard deviations above the normal value (i.e., average of 1961 to 1990).

majority of their primary energy. Some of the electricity consumed in the United States was generated using low or zero CO_2 emitting technologies such as hydroelectric or nuclear energy. In 1998, however, coal, natural gas, and petroleum were used to produce the majority—52, 15, and 4 percent, respectively—of the electricity generated by utilities in the United States (EIA 1999b).

Electric utilities were the dominant consumer of coal in the United States, accounting for 88 percent in 1998. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions. In fact, electric utilities consumed record amounts of coal (18,717 TBtu) in 1998. Overall, emissions from coal burned at electric utilities increased by 17 percent from 1990 to 1998. This increase in coal-related emissions from was alone responsible for 46 percent of the overall rise in CO_2 emissions from fossil fuel combustion.

In addition to this rise in consumption of coal, consumption of both natural gas and petroleum also rose in 1998 by 10 and 42 percent, respectively (EIA 1999f). This dramatic change in petroleum consumption was due mainly to a drop in petroleum prices (26 percent or the lowest price in 20 years) and the increased electricity demand which required the use of idle or underutilized petroleum units (EIA 1999b).

Demand for fossil fuels by electric utilities is also affected by the supply of electricity from other energy sources. In 1998, there was a significant decline in hydroelectric generation (8.5 percent) due mainly to reduced snowfall in the Northwest (EIA 1999b). This decline, however, offset by a slightly larger increase in electricity generation at nuclear power plants (7 percent) after seven generating units, that had previously been idle, were brought back into service (EIA 1999b).

It is important to note that the electric utility sector includes only regulated utilities. According to current EIA sectoral definitions, nonutility generators of electricity (e.g., independent power producers, qualifying cogenerators, and other small power producers) are included in the industrial sector. These nonutility generators produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market. The number and quantity of electricity generated by nonutilities has increased significantly as many states have begun deregulating their electricity markets.

A recent report by the U.S. Department of Energy and the EPA (DOE and EPA 1999) estimated emissions from the entire electric power industry, including regulated utilities and nonutilities. According to this report CO_2 emissions from nonutilities in 1998 were 56 MMTCE, bringing combined emissions from electricity generation up to 41 percent (605.5 MMTCE) of total U.S. CO_2 emissions from fossil fuel combustion, versus 37 percent from utilities alone. In other words, nonutilities were responsible for 10 percent of emissions from electricity generation. The growth in nonutility emissions from 1997 to 1998 was 9 percent. In future inventories, these nonutility generators will be removed from the industrial sector and incorporated into a single sector with electric utilities.

[BEGIN BOX]

Box 2-1: Sectoral Carbon Intensity Trends Related to Fossil Fuel and Overall Energy Consumption

Fossil fuels are the predominant source of energy in the United States, and carbon dioxide (CO_2) is emitted as a product from their complete combustion. Useful energy, however, can be generated from many other sources that do not emit CO_2 in the energy conversion process.[8] In the United States, useful energy is also produced from renewable (i.e., hydropower, biofuels, geothermal, solar, and wind) and nuclear sources.

Energy-related CO_2 emissions can be reduced by not only lowering total energy consumption (e.g., through conservation measures) but also by lowering the carbon intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of carbon emitted—in the form of CO_2—from the combustion of

[8] CO_2 emissions, however, may be generated from upstream activities (e.g., manufacture of the equipment).

fossil fuels is dependent upon the carbon content of the fuel and the fraction of that carbon that is oxidized. Fossil fuels vary in their average carbon content, ranging from about 13.7 MMTCE/EJ for natural gas to 26.4 MMTCE/EJ for coal and petroleum coke.[9] In general, the carbon intensity of fossil fuels is the highest for coal products, followed by petroleum and then natural gas. Other sources of energy, however, may be directly or indirectly carbon neutral (i.e., 0 MMTCE/EJ). Energy generated from nuclear and many renewable sources do not result in direct emissions of CO_2. Biofuels such as wood and ethanol are also considered to be carbon neutral, as the CO_2 emitted during combustion is assumed to be offset by the carbon sequestered in the growth of new biomass.[10] The overall carbon intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 2-9 provides a time series of the carbon intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For example, the carbon intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting or wood for heat. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest carbon intensity, which was related to the large percentage of energy derived from natural gas for heating. The carbon intensity of the commercial sector was greater than the residential sector for the period from 1990 to 1996, but then declined to an equivalent level as commercial businesses shifted away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher carbon intensities over this period. The carbon intensity of the transportation sector was closely related to the carbon content of petroleum products (e.g., motor gasoline and jet fuel), which were the primary sources of energy. Lastly, the electric utility sector had the highest carbon intensity due to its heavy reliance on coal for generating electricity.

Table 2-9: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (MMTCE/EJ)

Sector	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
Residential[a]	14.7	14.7	14.6	14.6	14.6	14.6	14.6	14.7	14.7
Commercial[a]	15.2	15.1	15.0	14.9	14.9	14.8	14.8	14.7	14.8
Industrial[a]	16.9	16.8	16.7	16.6	16.6	16.5	16.4	16.4	16.4
Transportation[a]	18.3	18.3	18.3	18.3	18.3	18.2	18.2	18.2	18.2
Electric Utilities[b]	22.4	22.4	22.4	22.5	22.4	22.4	22.6	22.6	22.5
All Sectors[c]	**18.7**	**18.7**	**18.6**	**18.7**	**18.6**	**18.6**	**18.6**	**18.6**	**18.7**

[a] Does not include electricity or renewable energy consumption.
[b] Does not include electricity produced using nuclear or renewable energy.
[c] Does not include nuclear or renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption. Exajoule (EJ) = 10^{18} joules = 0.9479 QBtu.

In contrast to Table 2-9, Table 2-10 presents carbon intensity values that incorporate energy consumed from all sources (i.e., fossil fuels, renewables, and nuclear). In addition, the emissions related to the generation of electricity have been attributed to both electric utilities and the sector in which that electricity was eventually consumed.[11] This table, therefore, provides a more complete picture of the actual carbon intensity of each sector per unit of energy consumed. The transportation sector in Table 2-10 emerges as the most carbon intensive when all sources of energy are included, due to its almost complete reliance on petroleum products and relatively minor amount of biomass based fuels such as ethanol. The “other end-use sectors” (i.e. the residential, commercial, and industrial sectors) use significant quantities of biofuels such as wood, thereby lowering the overall carbon intensity. The carbon intensity of electric utilities differs greatly from the scenario in Table 2-9 where only the energy consumed from the direct

[9] One exajoule (EJ) is equal to 10^{18} joules or 0.9478 QBtu.

[10] This statement assumes that there is no net loss of biomass-based carbon associated with the land use practices used to produce these biomass fuels.

[11] In other words, the emissions from the generation of electricity are intentionally double counted by attributing them both to utilities and the sector in which electricity consumption occurred.

combustion of fossil fuels was included. This difference is due almost entirely to the inclusion of electricity generation from nuclear and hydropower sources, which do not emit carbon dioxide.

Table 2-10: Carbon Intensity from Energy Consumption by Sector (MMTCE/EJ)

Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998
Transportation[a]	18.2	18.2	18.2	18.2	18.2	18.1	18.1	18.1	18.1
Other End-Use Sectors[a,b]	14.9	14.7	14.7	14.8	14.7	14.4	14.5	14.7	14.7
Electric Utilities[c]	15.3	15.0	15.2	15.3	15.2	14.8	14.9	15.4	15.4
All Sectors[d]	**15.8**	**15.6**	**15.7**	**15.7**	**15.7**	**15.5**	**15.5**	**15.7**	**15.7**

[a] Includes electricity (from fossil fuel, nuclear, and renewable sources) and direct renewable energy consumption.
[b] Other End-Use Sectors include the residential, commercial, and industrial sectors.
[c] Includes electricity generation from nuclear and renewable sources.
[d] Includes nuclear and renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption. Assumed that residential consumed all of the biofuel-based energy and 50 percent of the solar energy in the combined EIA residential/commercial sector category. Exajoule (EJ) = 10^{18} joules = 0.9479 QBtu.

By comparing the values in Table 2-9 and Table 2-10, a couple of observations can be made. The usage of renewable and nuclear energy sources has resulted in a significantly lower carbon intensity of the U.S. economy. However, over the nine year period of 1990 through 1998, the carbon intensity of U.S. fossil fuel consumption has been fairly constant, as the proportion of renewable and nuclear energy technologies has not changed significantly.

Figure 2-12 and Table 2-11 present the detailed CO_2 emission trends underlying the carbon intensity differences and changes described in Table 2-9. In Figure 2-12, changes over time in both overall end-use sector-related emissions and electricity-related emissions for each year since 1990 are highlighted. In Table 2-11 changes in emissions since 1990 are presented by sector and fuel type to provide more detail on these changes.

Figure 2-12: Change in CO_2 Emissions from Fossil Fuel Combustion Since 1990 by End-Use Sector

Table 2-11: Change in CO_2 Emissions from Direct Fossil Fuel Combustion Since 1990 (MMTCE)

Sector/Fuel Type	1991	1992	1993	1994	1995	1996	1997	1998
Residential	**2.7**	**5.1**	**10.5**	**7.9**	**8.3**	**15.5**	**11.6**	**4.2**
Coal	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.1)	(0.1)
Natural Gas	2.4	4.4	8.3	6.6	6.7	12.4	8.6	1.2
Petroleum	0.5	0.9	2.3	1.4	1.8	3.3	3.1	3.1
Commercial	**0.4**	**0.6**	**1.0**	**0.7**	**2.6**	**4.2**	**4.4**	**1.6**
Coal	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.1)	(0.2)
Natural Gas	1.6	2.7	4.3	4.0	6.0	7.9	8.7	6.0
Petroleum	(0.9)	(1.9)	(3.1)	(3.1)	(3.0)	(3.4)	(4.2)	(4.3)
Industrial	**(7.5)**	**6.0**	**4.9**	**10.9**	**12.7**	**21.1**	**21.7**	**14.5**
Coal	(3.6)	(5.9)	(6.3)	(5.8)	(6.4)	(8.6)	(9.0)	(9.4)
Natural Gas	1.9	7.7	13.2	14.7	21.6	26.3	24.9	22.0
Petroleum	(5.7)	4.2	(1.9)	2.0	(2.5)	3.4	5.8	1.8
Transportation	**(8.1)**	**1.5**	**9.6**	**22.8**	**28.2**	**42.1**	**43.9**	**50.7**
Coal	-	-	-	-	-	-	-	-
Natural Gas	(0.9)	(1.1)	(0.6)	0.3	0.6	0.7	1.4	1.0
Petroleum	(7.2)	2.6	10.1	22.5	27.3	41.4	42.5	49.7
Electric Utility	**(3.4)**	**(3.9)**	**13.9**	**17.3**	**17.4**	**36.4**	**56.2**	**73.3**
Coal	(1.8)	2.8	19.7	20.5	24.0	48.5	62.8	68.3
Natural Gas	(0.1)	(0.5)	(1.7)	2.8	6.0	(0.9)	2.4	6.6
Petroleum	(1.5)	(6.2)	(4.1)	(6.0)	(12.5)	(11.1)	(8.9)	(1.6)
U.S. Territories	**1.5**	**0.6**	**1.5**	**2.3**	**2.6**	**1.8**	**2.8**	**3.9**
Coal	+	+	0.1	0.1	0.1	0.1	0.1	0.1

Natural Gas	-	-	-	-	-	-	-	-
Petroleum	1.5	0.6	1.4	2.2	2.5	1.8	2.7	3.8
All Sectors	**(14.3)**	**9.9**	**41.4**	**61.8**	**71.8**	**121.2**	**140.6**	**148.1**

+ Does not exceed 0.05 MMTCE
- Not applicable
Note: Totals may not sum due to independent rounding.

[END BOX]

Methodology

The methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates (IPCC/UNEP/OECD/IEA 1997). A detailed description of the U.S. methodology is presented in Annex A, and is characterized by the following steps:

1. *Determine fuel consumption by fuel type and sector*. By aggregating consumption data by sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.), estimates of total U.S. fossil fuel consumption for a particular year were made. The United States does not include territories in its national energy statistics; therefore, fuel consumption data for territories was collected separately. [12]

2. *Determine the total carbon content of fuels consumed*. Total carbon was estimated by multiplying the amount of fuel consumed by the amount of carbon in each fuel. This total carbon estimate defines the maximum amount of carbon that could potentially be released to the atmosphere if all of the carbon in each fuel were converted to CO_2. The carbon content coefficients used by the United States are presented in Annex A.

3. *Subtract the amount of carbon stored in products*. Non-energy uses of fossil fuels can result in storage of some or all of the carbon contained in the fuel for some period of time, depending on the end-use. For example, asphalt made from petroleum can sequester up to 100 percent of the carbon for extended periods of time, while other fossil fuel products, such as lubricants or plastics, lose or emit some carbon when they are used and/or burned as waste. Aggregate U.S. energy statistics include consumption of fossil fuels for non-energy uses; therefore, the portion of carbon that remains in products after they are manufactured was subtracted from potential carbon emission estimates. The amount of carbon remaining in products was based on the best available data on the end-uses and fossil fuel products. These non-energy uses occurred in the industrial and transportation sectors and U.S. territories.[13]

4. *Adjust for carbon that does not oxidize during combustion*. Because combustion processes are not 100 percent efficient, some of the carbon contained in fuels is not emitted to the atmosphere. Rather, it remains behind as soot and ash. The estimated amount of carbon not oxidized due to inefficiencies during the combustion process was assumed to be 1 percent for petroleum and coal and 0.5 percent for natural gas (see Annex A).

5. *Subtract emissions from international bunker fuels*. According to the IPCC guidelines (IPCC/UNEP/OECD/IEA 1997) emissions from international transport activities, or bunker fuels, should not be included in national totals. Because U.S. energy consumption statistics include these bunker fuels—distillate

[12] Fuel consumption by U.S. territories (i.e. American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed emissions of13 MMTCE in 1998.

[13] See Waste Combustion section of Waste chapter for discussion of emissions from the combustion of plastics in the municipal solid waste steam.

fuel oil, residual fuel oil, and jet fuel—as part of consumption by the transportation sector, emissions from international transport activities were calculated separately and subtracted from emission estimates for the transportation sector. The calculations for emissions from bunker fuels follow the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, determination of carbon content, and adjustment for the fraction of carbon not oxidized).

6. *Allocate transportation emissions by vehicle type*. Because the transportation end-use sector was the largest direct consumer of fossil fuels in the United States,[14] a more detailed accounting of carbon dioxide emissions is provided. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. Specific data by vehicle type were not available for 1998; therefore, the 1997 percentage allocations were applied to 1998 fuel consumption data in order to estimate emissions in 1998. Military vehicle jet fuel consumption was provided by the Defense Energy Support Center, under Department of Defense's (DoD) Defense Logistics Agency and the Office of the Undersecretary of Defense (Environmental Security). The difference between total U.S. jet fuel consumption (as reported by DOE/EIA) and civilian air carrier consumption for both domestic and international flights (as reported by DOT/BTS and BEA) plus military jet fuel consumption is reported as "other" under the jet fuel category in Table 2-8, and includes such fuel uses as blending with heating oils and fuel used for chartered aircraft flights.

Data Sources

Data on fuel consumption for the United States and its territories, carbon content of fuels, and percent of carbon sequestered in non-energy uses were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). Fuel consumption data were obtained primarily from the *Monthly Energy Review* (EIA 1999f) and various EIA databases. Data on military jet fuel use was supplied by the Office of the Under Secretary of Defense (Environmental Security) and the Defense Energy Support Center (Defense Logistics Agency) of the U.S. Department of Defense (DoD). Estimates of international bunker fuel emissions are discussed in the section entitled International Bunker Fuels.

IPCC (IPCC/UNEP/OECD/IEA 1997) provided combustion efficiency rates for petroleum and natural gas. Bechtel (1993) provided the fraction oxidation values for coal. Vehicle type fuel consumption data for the allocation of transportation sector emissions were primarily taken from the *Transportation Energy Databook* prepared by the Center for Transportation Analysis at Oak Ridge National Laboratory (DOE 1993, 1994, 1995, 1996, 1997, 1998). All jet fuel and aviation gasoline was assumed to have been consumed in aircraft. Densities for each military jet fuel type were obtained from the Air Force (1998).

Carbon intensity estimates were developed using nuclear and renewable energy data from EIA (1998a) and fossil fuel consumption data as discussed above and presented in Annex A.

For consistency of reporting, the IPCC has recommended that national inventories report energy data (and emissions from energy) using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA, and used in this inventory, are, instead, "bottom up" in nature. In other words, they are collected through surveys at the point of delivery or use and aggregated to determine national totals.

[14] Electric utilities are not considered a final end-use sector, because they consume energy solely to provide electricity to the other sectors.

It is also important to note that EIA uses gross calorific values (GCV) (i.e., higher heating values) as its reporting standard for energy statistics. Fuel consumption activity data presented here have not been adjusted to correspond to international standard, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).

Uncertainty

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted, in principle is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and consumption of products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

There are uncertainties, however, concerning the consumption data sources, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., petroleum), the amount of carbon contained in the fuel per unit of useful energy can vary. Non-energy uses of the fuel can also create situations where the carbon is not emitted to the atmosphere (e.g., plastics, asphalt, etc.) or is emitted at a delayed rate. The proportions of fuels used in these non-energy production processes that result in the sequestration of carbon have been assumed. Additionally, inefficiencies in the combustion process, which can result in ash or soot remaining unoxidized for long periods, were also assumed. These factors all contribute to the uncertainty in the CO_2 estimates.

Other sources of uncertainty are fuel consumption by U.S. territories and bunker fuels consumed by the military. The United States does not collect as detailed energy statistics for its territories as for the fifty states and the District of Columbia. Therefore estimating both emissions and bunker fuel consumption by these territories is difficult.

For Table 2-8, uncertainties also exist as to the data used to allocate CO_2 emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom up estimates of fuel consumption by vehicle type do not match top down estimates from EIA. Further research is planned to better allocate detailed transportation end-use sector emissions.

For the United States, however, these uncertainties impact on overall CO_2 emission estimates are believed to be relatively small. For the United States, CO_2 emission estimates from fossil fuel combustion are considered accurate within one or two percent. See, for example, Marland and Pippin (1990).

Stationary Combustion (excluding CO_2)

Stationary combustion encompasses all fuel combustion activities except those related to transportation (i.e., mobile combustion). Other than carbon dioxide (CO_2), which was addressed in the previous section, gases from stationary combustion include the greenhouse gases methane (CH_4) and nitrous oxide (N_2O) and the criteria pollutants nitrogen oxides (NO_x), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs).[15] Emissions of these gases from stationary sources depend upon fuel characteristics, technology type, usage of pollution control equipment, and ambient environmental conditions. Emissions also vary with the size and vintage of the combustion technology as well as maintenance and operational practices.

Nitrous oxide and NO_x emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Carbon monoxide emissions from stationary combustion are generally a function of the efficiency of combustion and the use of emission controls; they are highest when less oxygen is present in the air-fuel mixture than is necessary for complete combustion. These conditions are most likely to occur during start-up and shut-down and during fuel switching (e.g., the switching of coal grades at a coal-burning electric utility plant). Methane and NMVOC emissions from

[15] Sulfur dioxide (SO_2) emissions from stationary combustion are addressed in Annex M.

stationary combustion are primarily a function of the CH_4 content of the fuel, combustion efficiency, and post-combustion controls.

Emissions of CH_4 increased slightly from 1990 to 1996, but fell to just below the 1990 level in 1998 to 2.2 MMTCE (379 Gg). This decrease in emissions was primarily due to lower wood consumption in the residential sector. Nitrous oxide emissions rose 8 percent since 1990 to 4.1 MMTCE (48 Gg) in 1998. The largest source of N_2O emissions was coal combustion by electric utilities, which alone accounted for 54 percent of total N_2O emissions from stationary combustion in 1998. Overall, though, stationary combustion is a small source of CH_4 and N_2O in the United States.

Table 2-12 through Table 2-15 provide CH_4 and N_2O emission estimates from stationary sources by sector and fuel type. See Annex C for estimates of NO_x, CO, and NMVOC emissions.

Table 2-12: CH_4 Emissions from Stationary Combustion (MMTCE)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998
Electric Utilities	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Fuel Oil	+	+	+	+	+	+	+	+	+
Natural Gas	+	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+	+
Industrial	**0.7**	**0.7**	**0.7**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**
Coal	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Wood	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial/Institutional	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Coal	+	+	+	+	+	+	+	+	+
Fuel Oil	0.1	+	+	+	+	+	+	+	+
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	+	+	+	0.1	0.1	0.1	0.1	0.1	0.1
Residential	**1.3**	**1.3**	**1.4**	**1.2**	**1.2**	**1.3**	**1.3**	**1.0**	**1.0**
Coal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.9	1.0	1.1	0.9	0.9	1.0	1.0	0.7	0.7
Total	**2.2**	**2.3**	**2.4**	**2.3**	**2.3**	**2.4**	**2.5**	**2.2**	**2.2**

+ Does not exceed 0.05 MMTCE
NA (Not Available)
Note: Totals may not sum due to independent rounding.

Table 2-13: N_2O Emissions from Stationary Combustion (MMTCE)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998
Electric Utilities	**2.0**	**2.0**	**2.0**	**2.1**	**2.1**	**2.1**	**2.2**	**2.3**	**2.3**
Coal	1.9	1.9	1.9	2.0	2.0	2.0	2.1	2.2	2.2
Fuel Oil	0.1	0.1	+	0.1	+	+	+	+	0.1
Natural Gas	+	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+	+
Industrial	**1.3**	**1.3**	**1.3**	**1.3**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**
Coal	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Oil	0.4	0.4	0.4	0.4	0.5	0.4	0.5	0.5	0.5
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
Commercial/Institutional	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+	+	+

Fuel Oil	+	+	+	+	+	+	+	+	+
Natural Gas	+	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+	+
Residential	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	+	+	+	+	+	+	+	+	+
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+	+	+
Wood	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1
Total	**3.7**	**3.6**	**3.7**	**3.8**	**3.8**	**3.9**	**4.0**	**4.0**	**4.1**

+ Does not exceed 0.05 MMTCE
NA (Not Available)
Note: Totals may not sum due to independent rounding.

Table 2-14: CH_4 Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998
Electric Utilities	**23**	**23**	**22**	**23**	**23**	**22**	**23**	**24**	**26**
Coal	16	16	16	17	17	17	18	19	19
Fuel Oil	4	4	3	3	3	2	2	2	4
Natural Gas	3	3	3	3	3	3	3	3	3
Wood	+	+	+	+	+	+	+	+	+
Industrial	**129**	**126**	**130**	**132**	**137**	**140**	**143**	**144**	**144**
Coal	27	26	25	25	25	24	24	23	23
Fuel Oil	17	16	17	17	18	17	18	19	18
Natural Gas	40	41	43	45	45	48	49	49	48
Wood	44	44	45	46	49	50	52	53	55
Commercial/Institutional	**23**	**23**	**23**	**35**	**35**	**36**	**38**	**36**	**34**
Coal	1	1	1	1	1	1	1	1	1
Fuel Oil	9	9	8	8	8	8	7	7	7
Natural Gas	13	13	14	14	14	15	15	16	15
Wood	+	+	+	13	13	13	14	12	11
Residential	**218**	**227**	**237**	**211**	**207**	**223**	**226**	**179**	**175**
Coal	19	17	17	17	17	16	17	17	17
Fuel Oil	13	13	13	14	13	14	14	14	14
Natural Gas	21	22	23	24	24	24	26	24	22
Wood	166	175	184	156	153	170	170	123	122
Total	**393**	**398**	**412**	**402**	**402**	**422**	**430**	**383**	**379**

+ Does not exceed 0.5 Gg
NA (Not Available)
Note: Totals may not sum due to independent rounding.

Table 2-15: N_2O Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998
Electric Utilities	**24**	**23**	**24**	**25**	**25**	**25**	**26**	**27**	**27**
Coal	23	22	23	24	24	24	25	26	26
Fuel Oil	1	1	1	1	1	+	+	+	1
Natural Gas	+	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+	+
Industrial	**16**	**15**	**16**	**16**	**16**	**16**	**17**	**17**	**17**
Coal	4	4	3	3	3	3	3	3	3
Fuel Oil	5	5	5	5	5	5	5	6	6
Natural Gas	1	1	1	1	1	1	1	1	1
Wood	6	6	6	6	7	7	7	7	7
Commercial/Institutional	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Coal	+	+	+	+	+	+	+	+	+

Fuel Oil	1	1	+	+	+	+	+	+	+
Natural Gas	+	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+	+
Residential	**3**	**4**	**4**	**3**	**3**	**4**	**4**	**3**	**3**
Coal	+	+	+	+	+	+	+	+	+
Fuel Oil	1	1	1	1	1	1	1	1	1
Natural Gas	+	+	+	+	+	+	1	+	+
Wood	2	2	2	2	2	2	2	2	2
Total	**44**	**43**	**44**	**45**	**45**	**46**	**47**	**48**	**48**

+ Does not exceed 0.5 Gg
NA (Not Available)
Note: Totals may not sum due to independent rounding.

Methodology

Methane and nitrous oxide emissions were estimated by multiplying emission factors (by sector and fuel type) by fossil fuel and wood consumption data. National coal, natural gas, fuel oil, and wood consumption data were grouped into four sectors—industrial, commercial/institutional, residential, and electric utilities.

For NO_x, CO, and NMVOCs, the major source categories included in this section are those used in EPA (1999): coal, fuel oil, natural gas, wood, other fuels (including LPG, coke, coke oven gas, and others), and stationary internal combustion. The EPA estimates emissions of NO_x, CO, and NMVOCs by sector and fuel source using a "bottom-up" estimating procedure. In other words, emissions were calculated either for individual sources (e.g., industrial boilers) or for multiple sources combined, using basic activity data as indicators of emissions. Depending on the source category, these basic activity data may include fuel consumption, fuel deliveries, tons of refuse burned, raw material processed, etc.

The EPA derived the overall emission control efficiency of a source category from published reports, the 1985 National Acid Precipitation and Assessment Program (NAPAP) emissions inventory, and other EPA databases. The U.S. approach for estimating emissions of NO_x, CO, and NMVOCs from stationary source combustion, as described above, is consistent with the methodology recommended by the IPCC (IPCC/UNEP/OECD/IEA 1997).

More detailed information on the methodology for calculating emissions from stationary sources, including emission factors and activity data, is provided in Annex B.

Data Sources

Emissions estimates for NO_x, CO, and NMVOCs in this section were taken directly from the EPA's *National Air Pollutant Emissions Trends: 1900 - 1998* (EPA 1999). Fuel consumption data were provided by the U.S. Energy Information Administration's *Annual Energy Review* (EIA 1999a) and *Monthly Energy Review* (EIA 1999b). Emission factors were provided by *the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997).

Uncertainty

Methane emission estimates from stationary sources are highly uncertain, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control). The uncertainties associated with the emission estimates of these gases are greater than with estimates of CO_2 from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the criteria pollutants, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

Mobile Combustion (excluding CO_2)

Mobile combustion emits greenhouse gases other than CO_2, including methane (CH_4), nitrous oxide (N_2O), and the criteria pollutants carbon monoxide (CO), nitrogen oxides (NO_x), and non-methane volatile organic compounds (NMVOCs).

As with stationary combustion, N_2O and NO_x emissions are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, as well as usage of pollution control equipment. Nitrous oxide, in particular, can be formed by the catalytic processes used to control NO_x and CO emissions. Carbon monoxide emissions from mobile source combustion are significantly affected by combustion efficiency and presence of post-combustion emission controls. Carbon monoxide emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. This occurs especially in idle, low speed and cold start conditions. Methane and NMVOC emissions from motor vehicles are a function of the CH_4 content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions, such as catalytic converters.

Emissions from mobile combustion were estimated by transport mode (e.g., highway, air, rail, and water) and fuel type—motor gasoline, diesel fuel, jet fuel, aviation gas, natural gas, liquefied petroleum gas (LPG), and residual fuel oil—and vehicle type. Road transport accounted for the majority of mobile source fuel consumption, and hence, the majority of mobile combustion emissions. Table 2-16 through Table 2-19 provide CH_4 and N_2O emission estimates from mobile combustion by vehicle type, fuel type, and transport mode.

Mobile combustion was responsible for a small portion of national CH_4 emissions but were the second largest source of N_2O in the United States. From 1990 to 1998, CH_4 emissions declined by 10 percent, to 1.3 MMTCE (232 Gg). Nitrous oxide emissions, however, rose 25 percent to 17.2 MMTCE (203 Gg) (see Figure 2-13). The reason for this conflicting trend was that the control technologies employed on highway vehicles in the United States lowered CO, NO_x, NMVOC, and CH_4 emissions, but resulted in higher average N_2O emission rates. Fortunately, since 1994 improvements in the emission control technologies installed on new vehicles have reduced emission rates of both NO_x and N_2O per vehicle mile traveled. Overall, CH_4 and N_2O emissions were dominated by gasoline-fueled passenger cars and light-duty gasoline trucks.

Figure 2-13: Mobile Source CH_4 and N_2O Emissions

A drop in gasoline prices combined with a strengthening U.S. economy caused an increase in emissions of criteria pollutants from 1990 through 1994. These factors pushed the vehicle miles traveled (VMT) by road sources up, resulting in increased fuel consumption and higher emissions. Some of this increased activity was later offset by an increasing portion of the U.S. vehicle fleet meeting established emissions standards.

Fossil-fueled motor vehicles comprise the single largest source of CO emissions in the United States and are a significant contributor to NO_x and NMVOC emissions.

Table 2-16: CH_4 Emissions from Mobile Combustion (MMTCE)

Fuel Type/Vehicle Type	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**

[16] See Annex C for a complete time series of criteria pollutant emission estimates for 1990 through 1998.

Gasoline Highway	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**1.2**	**1.2**	**1.2**	**1.2**
Passenger Cars	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.5	0.5
Light-Duty Trucks	0.5	0.5	0.6	0.6	0.6	0.6	0.5	0.5	0.5
Heavy-Duty Vehicles	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+	+	+
Diesel Highway	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Passenger Cars	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Non-Highway	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Ships and Boats	+	+	+	+	+	+	+	+	+
Locomotives	+	+	+	+	+	+	+	+	+
Farm Equipment	+	+	+	+	+	+	+	+	+
Construction Equipment	+	+	+	+	+	+	+	+	+
Aircraft	+	+	+	+	+	+	+	+	+
Other*	+	+	+	+	+	+	+	+	+
Total	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.4**	**1.4**	**1.4**	**1.3**

+ Does not exceed 0.05 MMTCE
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-17: N_2O Emissions from Mobile Combustion (MMTCE)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998
Gasoline Highway	**12.5**	**13.3**	**14.4**	**15.2**	**15.7**	**16.0**	**16.0**	**15.9**	**15.8**
Passenger Cars	8.0	8.0	8.3	8.6	8.8	8.9	8.9	8.7	8.6
Light-Duty Trucks	4.2	5.1	5.8	6.4	6.6	6.8	6.8	6.8	6.8
Heavy-Duty Vehicles	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4
Motorcycles	+	+	+	+	+	+	+	+	+
Diesel Highway	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**
Passenger Cars	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	0.4	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
Non-Highway	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**
Ships and Boats	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Locomotives	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Farm Equipment	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Construction Equipment	+	+	+	+	+	+	+	+	+
Aircraft	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Other*	+	+	+	+	+	+	+	+	+
Total	**13.8**	**14.6**	**15.7**	**16.5**	**17.1**	**17.4**	**17.5**	**17.3**	**17.2**

+ Does not exceed 0.05 MMTCE
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-18: CH_4 Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998
Gasoline Highway	**226**	**224**	**225**	**223**	**221**	**218**	**213**	**207**	**201**
Passenger Cars	124	114	109	104	102	100	98	95	94
Light-Duty Trucks	82	91	96	99	98	97	94	92	88
Heavy-Duty Vehicles	16	15	15	16	17	17	16	16	16
Motorcycles	4	4	4	4	4	4	4	4	3
Diesel Highway	**10**	**10**	**10**	**11**	**11**	**12**	**12**	**12**	**12**

Passenger Cars	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	10	10	10	10	11	11	11	12	12
Non-Highway	**21**	**21**	**21**	**21**	**21**	**22**	**22**	**20**	**19**
Ships and Boats	3	4	4	4	4	4	4	3	3
Locomotives	3	2	3	2	2	3	3	2	2
Farm Equipment	6	5	6	5	6	6	6	6	5
Construction Equipment	1	1	1	1	1	1	1	1	1
Aircraft	8	7	7	7	7	7	7	7	7
Other*	1	1	1	1	1	1	1	1	1
Total	**257**	**255**	**257**	**255**	**253**	**251**	**246**	**239**	**232**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-19: N_2O Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998
Gasoline Highway	**148**	**157**	**170**	**179**	**186**	**189**	**190**	**188**	**187**
Passenger Cars	95	95	99	101	104	106	105	103	102
Light-Duty Trucks	50	60	68	75	78	80	81	81	80
Heavy-Duty Vehicles	2	2	3	3	3	4	4	4	4
Motorcycles	+	+	+	+	+	+	+	+	+
Diesel Highway	**6**	**6**	**6**	**6**	**7**	**7**	**7**	**7**	**8**
Passenger Cars	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	5	5	6	6	6	6	7	7	7
Non-Highway	**10**	**9**	**10**	**9**	**10**	**10**	**10**	**9**	**9**
Ships and Boats	1	1	1	1	1	2	1	1	1
Locomotives	1	1	1	1	1	1	1	1	1
Farm Equipment	1	1	1	1	1	1	1	1	1
Construction Equipment	+	+	+	+	+	+	+	+	1
Aircraft	6	6	5	5	6	6	6	6	6
Other*	+	+	+	+	+	+	+	+	+
Total	**163**	**172**	**185**	**195**	**202**	**206**	**207**	**205**	**203**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Methodology

Estimates for CH_4 and N_2O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each category. Depending upon the category, activity data included such information as fuel consumption, fuel deliveries, and vehicle miles traveled (VMT). Emission estimates from highway vehicles were based on VMT and emission factors by vehicle type, fuel type, model year, and control technology. Fuel consumption data was employed as a measure of activity for non-highway vehicles and then fuel-specific emission factors were applied.[17] A complete discussion of the methodology used to estimate emissions from mobile combustion is provided in Annex C.

The EPA (1999) provided emissions estimates of NO_x, CO, and NMVOCs for eight categories of highway vehicles[18], aircraft, and seven categories of off-highway vehicles[19].

Data Sources

Emission factors used in the calculations of CH_4 and N_2O emissions are presented in Annex C. The *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997) provided emission factors for CH_4, and were developed using MOBILE5a, a model used by the Environmental Protection Agency (EPA) to estimate exhaust and running loss emissions from highway vehicles. The MOBILE5a model uses information on ambient temperature, vehicle speeds, national vehicle registration distributions, gasoline volatility, and other variables in order to produce these factors (EPA 1997).

Emission factors for N_2O from gasoline highway vehicles came from EPA (1998). This report contains emission factors for older passenger cars—roughly pre-1992 in California and pre-1994 in the rest of the United States—from published references, and for newer cars from a recent testing program at EPA's National Vehicle and Fuel Emissions Laboratory (NVFEL). These emission factors for gasoline highway vehicles are lower than the U.S. default values in the *Revised 1996 IPCC Guidelines*, but are higher than the European default values, both of which were published before the more recent tests and literature review conducted by the NVFEL. The U.S. default values in the *Revised 1996 IPCC Guidelines* were based on three studies that tested a total of five cars using European rather than U.S. test protocols. More details may be found in EPA (1998).

Emission factors for gasoline vehicles other than passenger cars were scaled from those for passenger cars with the same control technology, based on their relative fuel economy. This scaling was supported by limited data showing that light-duty trucks emit more N_2O than passenger cars with equivalent control technology. The use of fuel-consumption ratios to determine emission factors is considered a temporary measure only, to be replaced as additional testing data are available. For more details, see EPA (1998). Nitrous oxide emission factors for diesel highway vehicles were taken from the European default values found in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). There is little data addressing N_2O emissions from U.S. diesel-fueled vehicles, and in general, European countries have had more experience with diesel-fueled vehicles. U.S. default values in the *Revised 1996 IPCC Guidelines* were used for non-highway vehicles.

Activity data were gathered from several U.S. government sources including EIA (1999a), EIA (1999b), FHWA (1998), BEA (1999), DESC (1999), DOC (1999), FAA (1999), and DOT/BTS (1999). Control technology data for highway vehicles were obtained from the EPA's Office of Mobile Sources. Annual VMT data for 1990 through 1998 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database, as noted in EPA (1999).

Emissions estimates for NO_x, CO, NMVOCs were taken directly from the EPA's *National Air Pollutant Emissions Trends, 1900 - 1998* (EPA 1999).

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[17] The consumption of international bunker fuels is not included in these activity data, but are estimated separately under the International Bunker Fuels source category.

[18] These categories included: gasoline passenger cars, diesel passenger cars, light-duty gasoline trucks less than 6,000 pounds in weight, light-duty gasoline trucks between 6,000 and 8,500 pounds in weight, light-duty diesel trucks, heavy-duty gasoline trucks and buses, heavy-duty diesel trucks and buses, and motorcycles.

[19] These categories included: gasoline and diesel farm tractors, other gasoline and diesel farm machinery, gasoline and diesel construction equipment, snowmobiles, small gasoline utility engines, and heavy-duty gasoline and diesel general utility engines.

Uncertainty

Mobile source emission estimates can vary significantly due to assumptions concerning fuel type and composition, technology type, average speeds, type of emission control equipment, equipment age, and operating and maintenance practices. Fortunately, detailed activity data for mobile combustion were available, including VMT by vehicle type for highway vehicles. The allocation of this VMT to individual model years was done using the profile of U.S. vehicle usage by vehicle age in 1990 as specified in MOBILE 5a. Data to develop a temporally variable profile of vehicle usage by model year instead of age was not available.

Average emission factors were developed based on numerous assumptions concerning the age and model of vehicle; percent driving in cold start, warm start, and cruise conditions; average driving speed; ambient temperature; and maintenance practices. The factors for regulated emissions from mobile combustion—CO, NO_x, and hydrocarbons—have been extensively researched, and thus involve lower uncertainty than emissions of unregulated gases. Although methane has not been singled out for regulation in the United States, overall hydrocarbon emissions from mobile combustion—a component of which is methane—are regulated.

Compared to methane, CO, NO_x, and NMVOCs, there is relatively little data available to estimate emission factors for nitrous oxide. Nitrous oxide is not a criteria pollutant, and measurements of it in automobile exhaust have not been routinely collected. Research data has shown that N_2O emissions from vehicles with catalytic converters are greater than those without emission controls, and that vehicles with aged catalysts emit more than new ones. The emission factors used were, therefore, derived from aged cars (EPA 1998b). The emission factors used for Tier 0 and older cars were based on tests of 28 vehicles; those for newer vehicles were based on tests of 22 vehicles. This sample is small considering that it is being used to characterize the entire U.S. fleet, and the associated uncertainty is therefore large. Currently, N_2O gasoline highway emission factors for vehicles other than passenger cars are scaled based on those for passenger cars and their relative fuel economy. Actual measurements should be substituted for this procedure when they become available. Further testing is needed to reduce the uncertainty in emission factors for all classes of vehicles, using realistic driving regimes, environmental conditions, and fuels.

Although aggregate jet fuel and aviation gasoline consumption data has been used to estimate emissions from aircraft, the recommended method for estimating emissions in the *Revised 1996 IPCC Guidelines* is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions. The EPA is attempting to develop revised estimates based on this more detailed activity data, and these estimates are to be presented in future inventories.

Overall, uncertainty for N_2O emissions estimates is considerably higher than for CH_4, CO, NO_x, or NMVOC; however, all these gases involve far more uncertainty than CO_2 emissions from fossil fuel combustion.

U.S. jet fuel and aviation gasoline consumption is currently all attributed to the transportation sector by EIA, and it is assumed here that it is all used to fuel aircraft. However it is likely that some fuel purchased by airlines is not necessarily be used in aircraft, but instead used to power auxiliary power units, in ground equipment, and to test engines. Some jet fuel may also be used for other purposes such as blending with diesel fuel or heating oil.

Lastly, in EPA (1999), U.S. aircraft emission estimates for CO, NOx, and NMVOCs are based upon landing and take-off (LTO) cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates presented here overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including LTO cycles by aircraft on international flights but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes.

Coal Mining

All underground and surface coal mining liberates (i.e., releases) methane as part of normal operations. The amount of methane liberated during mining is primarily dependent upon the amount of methane stored in the coal and the surrounding strata. This *in situ* methane content is a function of the quantity of methane generated during the coal formation process and its ability to migrate through the surrounding strata over time. The degree of coalification—defined by the rank or quality of the coal formed—determines the amount of methane generated; higher ranked coals generate more methane. The amount of methane remaining in the coal and surrounding strata depends upon geologic characteristics such as pressure within a coal seam. Deeper coal deposits tend to retain more of the methane generated during coalification. Accordingly, deep underground coal seams generally have higher methane contents than shallow coal seams or surface deposits.

Underground coal mines contribute the largest share of methane emissions. All underground coal mines employ ventilation systems to ensure that methane levels remain within safe concentrations. These systems can exhaust significant amounts of methane to the atmosphere in low concentrations. Additionally, over twenty gassy U.S. coal mines supplement ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of methane before, during or after mining. In 1998, 12 coal mines collected methane from degasification systems and sold this gas to a pipeline, thus reducing emissions to the atmosphere. Surface coal mines also release methane as the overburden is removed and the coal is exposed; however, the level of emissions is much lower than underground mines. Additionally, after coal has been mined, small amounts of methane retained in the coal are released during processing, storage, and transport.

Total methane emissions in 1998 were estimated to be 17.8 MMTCE (3,104.2 Gg), declining 26 percent since 1990 (see Table 2-20 and Table 2-21). Of this amount, underground mines accounted for 64 percent, surface mines accounted for 15 percent, and post-mining emissions accounted for 22 percent. With the exception of 1994 and 1995, total methane emissions declined in each successive year during this period. In 1993, methane generated from underground mining dropped to a low of 2,327.7 Gg, primarily due to labor strikes at many large underground mines. In 1995, there was an increase in methane emissions from underground mining due to particularly increased emissions at the highest-emitting coal mine in the country. The decline in methane emissions from underground mines is the result of the mining of less gassy coal, and an increase in gas recovery and use. Surface mine emissions and post-mining emissions remained relatively constant from 1990 to 1998.

In 1994, EPA's Coalbed Methane Outreach Program (CMOP) began working with the coal industry and other stakeholders to identify and remove obstacles to investments in coal mine methane recovery and use projects. Reductions attributed to CMOP were estimated to be 0.7, 0.8, 1.0, 1.3, and 1.7 MMTCE in 1994 through 1998, respectively, compared to business-as-usual emissions.

Table 2-20: CH_4 Emissions from Coal Mining (MMTCE)

Activity	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
Underground Mining	17.1	16.4	15.6	13.3	13.1	14.2	12.6	12.3	11.4
Liberated	18.8	18.1	17.8	16.0	16.3	17.7	16.5	16.8	16.1
Recovered & Used	(1.6)	(1.7)	(2.1)	(2.7)	(3.2)	(3.4)	(3.8)	(4.6)	(4.8)
Surface Mining	2.8	2.6	2.6	2.5	2.6	2.4	2.5	2.6	2.6
Post- Mining (Underground)	3.6	3.4	3.3	3.0	3.3	3.3	3.4	3.5	3.4
Post-Mining (Surface)	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	**24.0**	**22.8**	**22.0**	**19.2**	**19.4**	**20.3**	**18.9**	**18.8**	**17.8**

Note: Totals may not sum due to independent rounding.

Table 2-21: CH_4 Emissions from Coal Mining (Gg)

Activity	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
Underground Mining	2,991	2,863	2,731	2,328	2,289	2,487	2,204	2,141	1,983
Liberated	3,279	3,152	3,102	2,795	2,848	3,086	2,875	2,938	2,814
Recovered & Used	(288)	(289)	(372)	(468)	(559)	(599)	(671)	(797)	(831)
Surface Mining	488	450	449	434	455	425	436	451	450
Post- Mining (Underground)	626	589	582	523	572	567	590	609	598
Post-Mining (Surface)	79	73	73	71	74	69	71	73	73
Total	**4,184**	**3,975**	**3,835**	**3,356**	**3,390**	**3,550**	**3,301**	**3,274**	**3,104**

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for estimating methane emissions from coal mining consists of two steps. The first step involves estimating methane emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to determine total emissions. The second step involves estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin-specific emissions factors.

Underground mines. Total methane emitted from underground mines is estimated to be the quantity of methane liberated from ventilation systems, plus methane liberated from degasification systems, minus methane recovered and used. The Mine Safety and Heath Administration (MSHA) samples methane emissions from ventilation systems for all mines with detectable[20] methane concentrations. These mine-by-mine measurements are used to estimate methane emissions from ventilation systems.

Some of the higher-emitting underground mines also use degasification systems (e.g., wells or boreholes) that remove methane before, during, or after mining. This methane can then be collected for use or vented to the atmosphere. Various approaches are employed to estimate the quantity of methane collected by each of the more than twenty mines using these systems, depending on available data. For example, some mines report to EPA the amounts of methane liberated from their degasification systems. For mines that sell recovered methane to a pipeline, pipeline sales data are used to estimate degasification emissions. Finally, for those mines for which no other data are available, default recovery efficiency values are developed, depending on the type of degasification system employed.

Finally, the amount of methane recovered by degasification systems and then used (i.e., not vented) is estimated. This calculation is complicated by the fact that methane is rarely recovered and used during the same year in which the particular coal seam is mined. In 1998, 12 active coal mines sold recovered methane to pipelines. Emissions avoided for these projects are estimated using gas sales data reported by various state agencies, and information supplied by coal mine operators regarding the number of years in advance of mining that gas recovery occurs. Additionally, some of the state agencies provide individual well production information, which is used to assign gas sales to a particular year.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining methane emissions are estimated by multiplying basin-specific coal production by basin-specific emissions factors. For surface mining, emissions factors are developed by assuming that surface mines emit from one to three times as much methane as the average *in situ* methane content of the coal. This accounts for methane released from the strata surrounding the coal seam. For this analysis, it is assumed that twice the average *in-situ* methane content is emitted. For post-mining emissions, the emission factor is assumed to be from 25 to 40 percent of the average *in situ* methane content of coals mined in the basin. For this analysis, it is assumed that 32.5 percent of the average *in-situ* methane content is emitted.

Data Sources

The Mine Safety and Health Administration provides mine-specific information on methane liberated from ventilation systems at underground mines. EPA develops estimates of methane liberated from degasification systems at underground mines based on available data for each of the mines employing these systems. The primary sources of data for estimating emissions avoided at underground mines are gas sales data published by state petroleum and natural gas agencies, information supplied by mine operators regarding the number of years in advance of mining that gas recovery occurred, and reports of gas used on-site. Annual coal production data are taken from the Energy

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[20] MSHA records coal mine methane readings with concentrations of greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

Information Agency's *Coal Industry Annual* (see Table 2-22) (EIA 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999). Data on *in situ* methane content and emissions factors are taken from EPA (1993).

Table 2-22: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,250	546,818	931,068
1991	368,635	532,656	901,291
1992	368,627	534,290	902,917
1993	318,478	539,214	857,692
1994	362,065	575,529	937,594
1995	359,477	577,638	937,115
1996	371,816	593,315	965,131
1997	381,620	607,163	988,783
1998*	377,397	636,972	1,014,369

*Total production for 1998 provided by EIA. Underground and surface proportions are estimated based on 1997 EIA data.

Uncertainty

The emission estimates from underground ventilation systems are based upon actual measurement data for mines with detectable methane emissions. Accordingly, the uncertainty associated with these measurements is estimated to be low. Estimates of methane liberated from degasification systems are less certain because EPA assigns default recovery efficiencies for a subset of U.S. mines. Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emissions factors from field measurements. Because underground emissions comprise the majority of total coal mining emissions, the overall uncertainty is estimated to be only ±15 percent.[21] Currently, the estimate does not include emissions from abandoned coal mines because of limited data. The EPA is conducting research on the feasibility of including an estimate in future years.

Natural Gas Systems

Methane emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas combusting engine and turbine exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions.

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, hundreds of thousands of miles of transmission pipeline, and over a million miles of distribution pipeline. The system, though, can be divided into four stages, each with different factors affecting methane emissions, as follows:

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, treatment facilities, gathering pipelines, and process units such as dehydrators and separators. Fugitive emissions and emissions from pneumatic devices account for the majority of emissions. Emissions from field production accounted for approximately 24 percent of methane emissions from natural gas systems between 1990 and 1998. Emissions rose between 1990 and 1996 due to an increased number of producing

[21] Preliminary estimate

gas wells and related equipment, but returned to the 1990 level of 8.0 MMTCE in 1998 due to a decrease in domestic production and improvements in technology coupled with the normal replacement of older equipment.

Processing. In this stage, processing plants remove various constituents from the raw gas before it is injected into the transmission system. Fugitive emissions from compressors, including compressor seals, were the primary contributor from this stage. Processing plants accounted for about 12 percent of methane emissions from natural gas systems during the period of 1990 through 1998.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production areas to distribution centers or large volume customers. Throughout the transmission system, compressor stations pressurize the gas to move it through the pipeline. Fugitive emissions from compressor stations and metering and regulating stations accounted for the majority of the emissions from transmission. Pneumatic devices and engine exhaust were smaller sources of emissions from transmission facilities. A gradual increase in transmission pipeline mileage has increased methane emissions from natural gas transmission. Methane emissions from transmission and storage accounted for approximately 40 percent of the emissions from natural gas systems during the period of 1990 through 1998.

Natural gas is also injected and stored in underground formations during periods of low demand, and withdrawn, processed, and distributed during periods of high demand. Compressors and dehydrators were the primary contributors to emissions from these storage facilities. Less than one percent of total emissions from natural gas systems can be attributed to storage facilities.

Distribution. The distribution of natural gas requires the use of low-pressure pipelines to deliver gas to customers. There were 955,000 miles of distribution pipelines (i.e., main) in 1997 (the latest year for which distribution pipeline mileage data is available), increasing from a 1990 figure of just over 837,000 miles (AGA, 1998). Distribution system emissions, which account for approximately 24 percent of emissions from natural gas systems, resulted mainly from fugitive emissions from gate stations and non-plastic piping. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced the growth in emissions from this stage.

Overall, natural gas systems emitted 33.6 MMTCE (5,860 Gg) of methane in 1998, a slight increase over 1990 emissions of 33.0 MMTCE (5,770) in 1990 (see Table 2-23 and Table 2-24). Even though transmission and distribution pipeline mileage and natural gas production have increased from 1990 to 1998, emissions over that period have remained relatively constant. Improvements in management practices and technology, along with the normal replacement of older equipment, helped to stabilize emissions. In addition, EPA's Natural Gas STAR Program, initiated in 1993, is working with the gas industry to promote profitable practices that reduce methane emissions. The program is estimated to have reduced emissions by 0.7, 1.2, 1.3, 1.8 and 2.2 MMTCE in 1994 through 1998, respectively. In Table 2-23 and Table 2-24, Natural Gas STAR reductions are included in the emission estimates for each sector of the natural gas industry and are also reflected in the total emission estimate.

Table 2-23: CH_4 Emissions from Natural Gas Systems (MMTCE)

Stage	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
Field Production	8.0	8.2	8.5	8.7	8.3	8.4	8.5	8.2	8.0
Processing	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.1	4.0
Transmission and Storage	12.7	12.9	12.9	13.1	13.3	13.0	13.1	13.2	13.5
Distribution	8.3	8.4	8.6	8.8	8.6	8.5	8.9	8.6	8.1
Total	**33.0**	**33.4**	**33.9**	**34.6**	**34.3**	**34.0**	**34.6**	**34.1**	**33.6**

Note: Totals may not sum due to independent rounding.

Table 2-24: CH_4 Emissions from Natural Gas Systems (Gg)

Stage	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
Field Production	1,404	1,427	1,478	1,513	1,450	1,469	1,489	1,435	1,388
Processing	702	693	698	704	724	712	708	710	698
Transmission and Storage	2,223	2,250	2,252	2,290	2,314	2,273	2,291	2,313	2,357
Distribution	1,441	1,470	1,496	1,535	1,499	1,477	1,553	1,504	1,416

Total	**5,770**	**5,840**	**5,923**	**6,042**	**5,987**	**5,931**	**6,041**	**5,961**	**5,860**

Note: Totals may not sum due to independent rounding.

Methodology

The foundation for the estimate of methane emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (GRI/EPA 1996). The GRI/EPA study developed over 100 detailed emission factors and activity levels through site visits to selected gas facilities, and arrived at a national point estimate for 1992. Since publication of this study, EPA conducted additional analysis to update the activity data for some of the components of the system, particularly field production equipment. Summing emissions across individual sources in the natural gas system provided a 1992 baseline emission estimate from which the emissions for the period 1990 through 1998 were derived.

Apart from the year 1992, detailed statistics on each of the over 100 activity levels were not available for the time series 1990 through 1998. To estimate these activity levels, aggregate annual statistics were obtained on select driving variables, including: number of producing wells, number of gas plants, miles of transmission pipeline, miles of distribution pipeline, and miles of distribution services. By assuming that the relationships among these variables remained constant (e.g., the number of heaters per well remained the same), the statistics on these variables formed the basis for estimating other activity levels.

For the period 1990 through 1995, the emission factors were held constant. A gradual improvement in technology and practices is expected to reduce the emission factors slightly over time. To reflect this trend, the emission factors were reduced by about 0.2 percent per year starting with 1996, a rate that, if continued, would lower the emission factors by 5 percent in 2020. See Annex E for more detailed information on the methodology and data used to calculate methane emissions from natural gas systems.

Data Sources

Activity data were taken from the American Gas Association (AGA 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999), *Natural Gas Annual* (EIA 1998), and *Natural Gas Monthly* (EIA 1998), Independent Petroleum Association of America (IPAA 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998), and the Department of Transportation’s Office of Pipeline Safety (OPS 2000). The U.S. Department of Interior (DOI 1997, 1998, 1999) supplied offshore platform data. All emission factors were taken from GRI/EPA (1996).

Uncertainty

The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. Despite the difficulties associated with estimating emissions from this source, the uncertainty in the total estimated emissions are believed to be on the order of ±40 percent.

Petroleum Systems

Methane emissions from petroleum systems are primarily associated with crude oil production, transportation, and refining operations. During each of these activities, methane is released to the atmosphere as fugitive emissions, vented emissions, operational upset emissions, and emissions from the combustion of fuels. These activities and associated methane emissions are detailed below.

Production Field Operations. Production field operations account for approximately 97 percent of total methane emissions from petroleum systems. The major sources of methane from production operations are venting from storage tanks and pneumatic devices, wellhead fugitives, combustion products, and process upsets. Vented methane from oil wells, storage tanks, and related production field processing equipment was the primary contributor to emissions from the oil industry, accounting for, on average, 89 percent. Field storage tanks and natural-gas-powered pneumatic devices used to operate valves and small pumps were the dominant contributors to venting emissions. Oil wells and offshore platforms accounted for most of the remaining venting emissions.

Fugitive and combustion emissions from production field operations accounted for three percent and two percent, respectively, of total methane emissions from the oil industry. Most fugitive methane emissions in the field were from oil wellheads and the equipment used to separate natural gas and water from the crude oil. Nearly all of the combustion emissions in the field were from engine exhaust. The EPA expects future emissions from production fields to decline as the number of oil wells declines and crude production slows.

Crude Oil Transportation. Crude transportation activities accounted for less than one half percent of total methane emissions from the oil industry. Venting from tanks and marine vessel loading operations accounted for the majority of methane emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, accounted for the remainder.

Crude Oil Refining. Crude oil refining processes and systems accounted for only two percent of total methane emissions from the oil industry because most of the methane in crude oil is removed or escapes before the crude oil is delivered to the refineries. Within refineries, vented emissions accounted for 86 percent, while fugitive and combustion emissions were seven percent each. Refinery system blowdowns for maintenance and the process of asphalt blowing—with air to harden it—were the primary venting contributors. Most of the fugitive emissions from refineries were from leaks in the fuel gas system. Refinery combustion emissions accumulate from small amounts of unburned methane in process heater stack emissions and from unburned methane in engine exhausts and flares.

The EPA estimates total methane emissions from petroleum systems in 1998 were 6.3 MMTCE (1,108 Gg). Since 1990, emissions declined gradually primarily due to a decline in domestic oil production. Emission estimates are provided below in Table 2-25 and Table 2-26.

Table 2-25: CH_4 Emissions from Petroleum Systems (MMTCE)

Activity	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
Production Field Operations	**7.2**	**7.3**	**7.1**	**6.7**	**6.6**	**6.5**	**6.4**	**6.4**	**6.2**
Tank venting	3.2	3.3	3.1	3.0	2.9	2.8	2.8	2.8	2.7
Pneumatic device venting	3.2	3.2	3.1	3.0	2.9	2.9	2.8	2.8	2.7
Wellhead fugitives	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combustion & process upsets	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Misc. venting & fugitives	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Crude Oil Transportation	+	+	+	+	+	+	+	+	+
Refining	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**
Total	**7.4**	**7.5**	**7.2**	**6.9**	**6.7**	**6.7**	**6.5**	**6.5**	**6.3**

+ Does not exceed 0.05 MMTCE
Note: Totals may not sum due to independent rounding.

Table 2-26: CH_4 Emissions from Petroleum Systems (Gg)

Activity	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
Production Field Operations	**1,263**	**1,276**	**1,232**	**1,175**	**1,144**	**1,136**	**1,111**	**1,109**	**1,075**
Tank venting	564	570	548	519	502	493	485	484	466
Pneumatic device venting	559	564	545	521	506	507	491	490	475
Wellhead fugitives	24	26	25	24	25	25	25	24	24
Combustion & process upsets	46	46	45	45	45	45	45	46	45
Misc. venting & fugitives	70	70	69	67	66	66	65	65	64
Crude Oil Transportation	**7**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**
Refining	**25**	**24**	**24**	**25**	**25**	**25**	**26**	**27**	**27**
Total	**1,294**	**1,307**	**1,262**	**1,206**	**1,175**	**1,168**	**1,143**	**1,142**	**1,108**

Note: Totals may not sum due to independent rounding.

Methodology

The EPA's methodology for estimating methane emissions from petroleum systems is based on a comprehensive study of methane emissions from U.S. petroleum systems, *Estimates of Methane Emissions from the U.S. Oil Industry (Draft Report)* (EPA 1999). The study estimated emissions from 70 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 39 activities for crude oil production field operations, 11 for crude oil transportation activities, and 20 for refining operations. Annex F explains the emission estimates for these 70 activities in greater detail. The estimate of methane emissions from petroleum systems does not include emissions downstream from oil refineries because these emissions are very small compared to methane emissions upstream from oil refineries.

The methodology for estimating methane emissions from the 70 oil industry activities employs emission factors and activity factors initially developed in EPA (1999). The EPA estimates emissions for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by their corresponding activity factor (e.g., equipment count or frequency of activity). The report (EPA 1999) provides emission factors and activity factors for all activities except those related to offshore oil production. For offshore oil production, the EPA calculated an emission factor by dividing an emission estimate from the Minerals Management Service (MMS) by the number of platforms (the activity factor).

The EPA collected activity factors for 1990 through 1998 from a wide variety of historical resources. For 1995, data on activity factors were available; however, some activity factor data are not reported for other years. When activity factor data were not available, the EPA employed one of three options. Where appropriate, the activity factor was assumed to be directly proportional to annual oil production. (Proportionality constants were calculated by dividing the activity factor for 1995 by the annual oil production for 1995. The resulting proportionality constants were then multiplied by the annual oil production in years for which activity factors must be estimated.) In other cases, the activity factor was kept constant between 1990 and 1998. Lastly, 1997 data was used when 1998 data were not yet available.

Emission factors were held constant for the period 1990 through 1998, with the exception of engine emissions. Over time, more efficient engines are used to drive pumps, compressors, and generators. The emission factor for these engines was adjusted accordingly.

Data Sources

Nearly all emission factors were taken from earlier work performed by Radian International LLC (Radian 1996e). Other emission factors were taken from API publication 4638 (API 1996), EPA default values, MMS reports (MMS 1995 and 1999), the Exploration and Production (E&P) Tank model (API and GRI), reports by the Canadian Association of Petroleum Producers (CAPP 1992 and 1993), and consensus of industry peer review panels.

The EPA uses many references to obtain activity factors. Among the more important references are Energy Information Administration annual and monthly reports (EIA 1995, 1996, 1997, 1998), the API *Basic Petroleum Data Book* (API 1997 and 1999), the GRI/EPA report (Radian 1996a-d), *Methane Emissions from the Natural Gas Industry,* consensus of industry peer review panels, MMS reports (MMS 1995 and 1999), and the *Oil & Gas Journal* (OGJ 1990-1998a,b). Appendix F provides a complete list of references.

Uncertainty

The detailed, bottom-up analysis used to evaluate U.S. petroleum systems for the current Inventory reduces the uncertainty related to the methane emission estimates compared to previous estimates. However, a number of uncertainties remain. Because published activity factors are not available every year for all 70 activities analyzed for petroleum systems, the EPA must estimate some of them. For example, there is uncertainty associated with the estimate of annual venting emissions in production field operations because a recent census of tanks and other tank battery equipment, such as separators and pneumatic devices, is not available. These uncertainties are important because the production sector accounted for 97 percent of total 1998 methane emissions from petroleum systems.

Uncertainties are also associated with emission factors because highly variable emission rates are summarized in one emission factor. The majority of methane emissions occur during production field operations, where methane can first escape crude oil, so a better understanding of tank battery equipment and tanks would reduce the uncertainty associated with the estimate of methane emissions from petroleum systems. Table 2-27 provides emission estimate ranges given the uncertainty in the estimates of vented emissions from producing field tanks and pneumatic devices.

Table 2-27: Uncertainty in CH_4 Emissions from Production Field Operations (Gg)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998
Tank venting (point estimate)	**564**	**570**	**548**	**519**	**502**	**493**	**485**	**484**	**466**
Low	423	427	411	389	377	370	364	363	349
High	705	712	685	649	628	617	606	605	582
Pneumatic devices (point estimate)	**559**	**564**	**545**	**521**	**506**	**507**	**491**	**490**	**475**
Low	372	376	363	347	338	338	328	327	317
High	698	705	681	651	633	634	614	613	594

Natural Gas Flaring and Criteria Pollutant Emissions from Oil and Gas Activities

The flaring of natural gas from oil wells is a small source of carbon dioxide (CO_2). In addition, oil and gas activities also release small amounts of nitrogen oxides (NO_x), carbon monoxide (CO), and nonmethane volatile organic compounds (NMVOCs). This source accounts for only a small proportion of overall emissions of each of these gases. Emissions of CO_2, NO_x, and CO from petroleum and natural gas production activities were all less than 1 percent of national totals, while NMVOC emissions were roughly 2 percent of national totals.

Carbon dioxide emissions from petroleum production result from natural gas that is flared (i.e., combusted) at the production site. Barns and Edmonds (1990) noted that of total reported U.S. venting and flaring, approximately 20 percent may be vented, with the remaining 80 percent flared; however, it is now believed that flaring accounts for an even greater proportion, although some venting still occurs. Methane emissions from venting are accounted for under Petroleum Systems. For 1998, the CO_2 emissions from the flaring were estimated to be approximately 3.4 MMTCE (12,296 Gg), an increase of 148 percent since 1990 (see Table 2-28).

Table 2-28: CO_2 Emissions from Natural Gas Flaring

Year	MMTCE	Gg
1990	2.5	9,097
1991	2.8	10,295
1992	2.8	10,169
1993	3.7	13,716
1994	3.8	13,800
1995	4.7	17,164
1996	4.5	16,506
1997	4.2	15,521
1998	3.9	14,214

Criteria pollutant emissions from oil and gas production, transportation, and storage, constituted a relatively small and stable portion of the total emissions of these gases from the 1990 to 1997 (see Table 2-29).

Table 2-29: NO_x, NMVOCs, and CO Emissions from Oil and Gas Activities (Gg)

Year	NO_x	CO	NMVOCs
1990	139	302	555
1991	110	313	581
1992	134	337	574
1993	111	337	588
1994	106	307	587
1995	100	316	582
1996	121	287	459

1997	121	292	461

Methodology

The estimates for CO_2 emissions were prepared using an emission factor of 14.92 MMTCE/QBtu of flared gas, and an assumed flaring efficiency of 100 percent. The quantity of flared gas was estimated as the total reported vented and flared gas minus a constant 12,031 million cubic feet, which was assumed to be vented.[22]

Criteria pollutant emission estimates for NO_x, CO, and NMVOCs were determined using industry-published production data and applying average emission factors.

Data Sources

Activity data in terms of total natural gas vented and flared for estimating CO_2 emissions from natural gas flaring were taken from EIA's *Natural Gas Annual* (EIA 1998). The emission and thermal conversion factors were also provided by EIA (see Table 2-30).

EPA (1999) provided emission estimates for NO_x, CO, and NMVOCs from petroleum refining, petroleum product storage and transfer, and petroleum marketing operations. Included are gasoline, crude oil and distillate fuel oil storage and transfer operations, gasoline bulk terminal and bulk plants operations, and retail gasoline service stations operations.

Table 2-30: Total Natural Gas Reported Vented and Flared (Million Ft^3) and Thermal Conversion Factor (Btu/Ft^3)

Year	Vented and Flared	Thermal Conversion Factor
1990	150,415	1,106
1991	169,909	1,108
1992	167,519	1,110
1993	226,743	1,106
1994	228,336	1,105
1995	283,739	1,106
1996	272,117	1,109
1997	263,819	1,107
1998	261,000	1,107

Uncertainty

Uncertainties in CO_2 emission estimates primarily arise from assumptions concerning what proportion of natural gas is flared and the flaring efficiency. The portion assumed vented as methane in the methodology for Petroleum Systems is currently held constant over the period 1990 through 1998 due to the uncertainties involved in the estimate. Uncertainties in criteria pollutant emission estimates are partly due to the accuracy of the emission factors used and projections of growth.

International Bunker Fuels

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the United Nations Framework Convention on Climate Change (UNFCCC), are currently not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was

[22] See the methodological discussion under Petroleum Systems for the basis of the portion of natural gas assumed vented.

made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.[23] These decisions are reflected in the *Revised 1996 IPCC Guidelines*, in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC/UNEP/OECD/IEA 1997). The Parties to the UNFCCC have yet to decide on a methodology for allocating these emissions.[24]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), carbon monoxide (CO), oxides of nitrogen (NO_x), nonmethane volatile organic compounds (NMVOCs), particulate matter, and sulfur dioxide (SO_2).[25] Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine. Emissions from ground transport activities—by road vehicles and trains—even when crossing international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC Guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC Guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC Guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[26]

Emissions of CO_2 from aircraft are a function of fuel use, whereas emissions per flight or ton-mile in the case of cargo, are a function of flight path, fuel efficiency of the aircraft and its engines, occupancy, and load factor. Methane, N_2O, CO, NO_x, and NMVOC emissions depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). Methane, CO, and NMVOCs are the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N_2O and NO_x are primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. The impact of NO_x on atmospheric chemistry depends on the altitude of the actual emission. The cruising altitude of supersonic aircraft, near or in the ozone layer, is higher than that of subsonic aircraft. At this higher altitude, NO_x emissions contribute to ozone depletion.[27] At the cruising altitudes of subsonic aircraft, however, NO_x emissions contribute to the formation of ozone. At these lower altitudes, the positive radiative forcing effect of ozone is most potent.[28] The vast majority of aircraft NO_x emissions occur at these lower cruising altitudes of commercial subsonic aircraft (NASA 1996).[29]

International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating

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[23] See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c) (contact secretariat@unfccc.de).

[24] See FCCC/SBSTA/1996/9/Add.1 and Add.2 for a discussions of allocation options for international bunker fuels (see http://www.unfccc.de/fccc/docs/1996/sbsta/09a01.pdf and /09a02.pdf).

[25] Sulfur dioxide emissions from jet aircraft and marine vessels, although not estimated here, are mainly determined by the sulfur content of the fuel. In the U.S., jet fuel, distillate diesel fuel, and residual fuel oil average sulfur contents of 0.05, 0.3, and 2.3 percent, respectively. These percentages are generally lower than global averages.

[26] Naphtha-type jet fuel is used primarily by the military in turbojet and turboprop aircraft engines.

[27] In 1996, there were only around a dozen civilian supersonic aircraft in service around the world which flew at these altitudes, however.

[28] However, at this lower altitude, ozone does little to shield the earth from ultraviolet radiation.

[29] Cruise altitudes for civilian subsonic aircraft generally range from 8.2 to 12.5 km (27,000 to 41,000 feet).

greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. Carbon dioxide is the primary greenhouse gas emitted from marine shipping. In comparison to aviation, the atmospheric impacts of NO_x from shipping are relatively minor, as the emissions occur at ground level.

Overall, aggregate greenhouse gas emissions in 1998 from the combustion of international bunker fuels from both aviation and marine activities decreased by 3 percent since 1990, to 31.6 MMTCE (see Table 2-31). Although emissions from international flights departing from the United States have increased significantly (22 percent), emissions from international shipping voyages departing the United States appear to have decreased by 19 percent since 1990. Increased military activity during the Persian Gulf War resulted in an increased level of military marine emissions in 1990 and 1991; civilian marine emissions during this period exhibited a similar trend.[30] Since 1994, marine emissions have steadily increased. The majority of these emissions were in the form of carbon dioxide; however, small amounts of CH_4 and N_2O were also emitted. Of the criteria pollutants, emissions of NO_x by aircraft at cruising altitudes are of primary concern because of their effects on ozone formation (see Table 2-32).

Emissions from both aviation and marine international transport activities are expected to grow in the future as both air traffic and trade increase, although emission rates should decrease over time due to technological changes.[31]

Table 2-31: Emissions from International Bunker Fuels (MMTCE)

Gas/Mode	1990	1991	1992	1993	1994	1995	1996	1997	1998
CO_2	**32.2**	**32.7**	**30.0**	**27.2**	**26.7**	**27.5**	**27.9**	**29.9**	**31.3**
Aviation	12.7	12.7	12.9	13.0	13.2	13.9	14.2	15.2	15.5
Marine	19.4	20.0	17.1	14.3	13.6	13.6	13.7	14.7	15.8
CH_4	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Aviation	+	+	+	+	+	+	+	+	+
Marine	+	+	+	+	+	+	+	+	+
N_2O	**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**
Aviation	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
Marine	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**32.5**	**33.0**	**30.3**	**27.5**	**27.0**	**27.8**	**28.1**	**30.2**	**31.6**

+ Does not exceed 0.05 MMTCE
Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 2-32: Emissions from International Bunker Fuels (Gg)

Gas/Mode	1990	1991	1992	1993	1994	1995	1996	1997	1998
CO_2	**117,965**	**120,019**	**109,965**	**99,886**	**98,017**	**101,014**	**102,197**	**109,788**	**114,700**
Aviation	46,728	46,682	47,143	47,615	48,327	51,093	52,135	55,899	56,917
Marine	71,237	73,337	62,822	52,270	49,690	49,921	50,062	53,889	57,783
CH_4	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
Aviation	1	1	1	1	1	1	1	2	2
Marine	1	1	1	0	0	0	0	0	1
N_2O	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Aviation	1	1	1	2	2	2	2	2	2
Marine	2	2	2	1	1	1	1	1	1
CO	**118**	**120**	**114**	**109**	**109**	**113**	**115**	**124**	**128**

30 See Uncertainty section for a discussion of data quality issues.

31 Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

Aviation	77	77	77	78	80	84	86	92	94
Marine	42	43	37	31	29	29	29	32	34
NO_x	**2,093**	**2,148**	**1,870**	**1,591**	**1,523**	**1,541**	**1,548**	**1,665**	**1,776**
Aviation	184	184	186	188	191	202	207	221	225
Marine	1,908	1,964	1,683	1,403	1,332	1,339	1,341	1,444	1,550
NMVOC	**62**	**64**	**56**	**49**	**47**	**48**	**49**	**52**	**55**
Aviation	12	11	12	12	12	13	13	14	14
Marine	51	52	45	37	35	36	36	38	41

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Methodology

Emissions of CO_2 were estimated through the application of carbon content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO_2 from Fossil Fuel Combustion. A complete description of the methodology and a listing of the various factors employed can be found in Annex A. See Annex G for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH_4, N_2O, CO, NO_x, and NMVOCs were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Data Sources

Carbon content and fraction oxidized factors for kerosene-type and naptha-type jet fuel, distillate fuel oil, and residual fuel oil were taken directly from the Energy Information Administration (EIA) of the U.S. Department of Energy and are presented in Annex A. Heat content and density conversions were taken from EIA (1998) and USAF (1998). Emission factors used in the calculations of CH_4, N_2O, CO, NO_x, and NMVOC emissions were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.09 for CH_4, 0.1 for N_2O, 5.2 for CO, 12.5 for NO_x, and 0.78 for NMVOCs. For marine vessels consuming either distillate diesel or residual fuel oil the following values, in the same units, except where noted, were employed: 0.03 for CH_4, 0.08 for N_2O, 1.9 for CO, 87 for NO_x, and 0.052 g/MJ for NMVOCs.

Activity data on aircraft fuel consumption were collected from three government agencies. Jet fuel consumed by U.S. flag air carriers for international flight segments was supplied by the Bureau of Transportation Statistics (DOT/BTS 1999). It was assumed that 50 percent of the fuel used by U.S. flagged carriers for international flights—both departing and arriving in the United States—was purchased domestically for flights departing from the United States. In other words, only one-half of the total annual fuel consumption estimate was used in the calculations. Data on jet fuel expenditures by foreign flagged carriers departing U.S. airports was taken from unpublished data collected by the Bureau of Economic Analysis (BEA) under the U.S. Department of Commerce (BEA 1999). Approximate average fuel prices paid by air carriers for aircraft on international flights was taken from DOT/BTS (1999) and used to convert the BEA expenditure data to gallons of fuel consumed. Data on jet fuel expenditures by the U.S. military was supplied by the Office of the Under Secretary of Defense (Environmental Security), U.S. Department of Defense (DoD). Estimates of the percentage of each services' total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Data on fuel delivered to the military within the United States was provided from unpublished data by the Defense Energy Support Center, under DoD's Defense Logistics Agency (DESC 1999). Together, the data allow the quantity of fuel used in military international operations to be estimated. Jet fuel densities for each fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 2-33. See Annex G for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1998). Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by the Defense Energy Support Center (DESC). The total amount of fuel provided to naval vessels was reduced by 13 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in Table 2-34.

Table 2-33: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	1990	1991	1992	1993	1994	1995	1996	1997	1998
U.S. Carriers	1,982	1,970	2,069	2,078	2,155	2,256	2,329	2,482	2,363
Foreign Carriers	2,062	2,075	2,185	2,252	2,326	2,549	2,629	2,918	3,138
U.S. Military	862	855	700	677	608	581	540	496	502
Total	**4,905**	**4,900**	**4,954**	**5,007**	**5,090**	**5,385**	**5,497**	**5,895**	**6,003**

Note: Totals may not sum due to independent rounding.

Table 2-34: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998
Residual Fuel Oil	5,137	5,354	4,475	3,567	3,504	3,495	3,583	3,843	3,974
Distillate Diesel Fuel & Other	598	595	561	609	510	573	456	421	627
U.S. Military Naval Fuels	522	481	491	448	364	334	362	477	506
Total	**6,257**	**6,431**	**5,527**	**4,624**	**4,378**	**4,402**	**4,402**	**4,740**	**5,107**

Note: Totals may not sum due to independent rounding.

Uncertainty

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[32] For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Particularly for aviation, the DOT/BTS (1998) international flight segment fuel data used for U.S. flagged carriers does not include smaller air carriers and unfortunately defines flights departing to Canada and some flights to Mexico as domestic instead of international. As for the BEA (1998) data on foreign flagged carriers, there is some uncertainty as to the average fuel price, and to the completeness of the data. It was also not possible to determine what portion of fuel purchased by foreign carriers at U.S. airports was actually used on domestic flight segments; this error, however, is believed to be small.[33]

Although aggregate fuel consumption data has been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the *Revised 1996 IPCC Guidelines* is to use data by

[32] See uncertainty discussions under CO_2 from Fossil Fuel Combustion and Mobile Combustion.

[33] Although foreign flagged air carriers are prevented from providing domestic flight services in the United States, passengers may be collected from multiple airports before an aircraft actually departs on its international flight segment. Emissions from these earlier domestic flight segments should be classified as domestic, not international, according to the IPCC.

specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions of gases other than CO_2.[34] The EPA is developing revised estimates based on this more detailed activity data, and these estimates are to be presented in future inventories.

There is also concern as to the reliability of the existing DOC (1998) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation. Of note is that fuel consumption data were not available for the year 1990; therefore, an average of 1989 and 1991 data was employed.

Wood Biomass and Ethanol Consumption

The combustion of biomass fuels—such as wood, charcoal, and wood waste—and biomass-based fuels—such as ethanol from corn and woody crops—generates carbon dioxide (CO_2). However, in the long run the carbon dioxide emitted from biomass consumption does not increase atmospheric carbon dioxide concentrations, assuming the biogenic carbon emitted is offset by the uptake of CO_2 resulting from the growth of new biomass. As a result, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel-based emissions and are not included in the U.S. totals. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands are accounted for in the Land-Use Change and Forestry chapter.

In 1998, CO_2 emissions due to burning of woody biomass within the industrial and residential/commercial sectors and by electric utilities were about 64.2 MMTCE (235,554 Gg) (see Table 2-35 and Table 2-36). As the largest consumer of woody biomass, the industrial sector in 1998 was responsible for 83 percent of the CO_2 emissions from this source. The combined residential/commercial[35] sector was the second largest emitter, making up 16 percent of total emissions from woody biomass. The commercial end-use sector and electric utilities accounted for the remainder.

Table 2-35: CO_2 Emissions from Wood Consumption by End-Use Sector (MMTCE)

End-Use Sector	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
Electric Utility	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Industrial	42.4	42.3	44.5	45.4	48.3	49.8	51.6	52.1	53.6
Residential/Commercial	12.7	13.4	14.1	12.9	12.7	14.0	14.0	10.4	10.2
Total	**55.6**	**56.2**	**59.0**	**58.8**	**61.4**	**64.2**	**66.1**	**62.9**	**64.2**

Note: Totals may not sum due to independent rounding.

Table 2-36: CO_2 Emissions from Wood Consumption by End-Use Sector (Gg)

End-Use Sector	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**
Electric Utility	1,715	1,698	1,725	1,636	1,635	1,356	1,580	1,542	1,598
Industrial	155,614	155,232	163,195	166,480	177,145	182,658	189,370	190,968	196,561
Residential/Commercial	46,424	48,981	51,537	47,303	46,504	51,218	51,440	37,959	37,395
Total	**203,753**	**205,910**	**216,457**	**215,419**	**225,284**	**235,232**	**242,390**	**230,470**	**235,554**

Note: Totals may not sum due to independent rounding.

[34] It should be noted that in the EPA's *National Air Pollutant Emissions Trends, 1900 - 1998* (EPA 1999), U.S. aviation emission estimates for CO, NOx, and NMVOCs are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates given under Mobile Source Fossil Fuel Combustion overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. EPA (1998) is also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

[35] For this emissions source, data are not disaggregated into residential and commercial sectors.

Biomass-derived fuel consumption in the United States consisted mainly of ethanol use in the transportation sector. Ethanol is primarily produced from corn grown in the Midwest, and was used mostly in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles. Ethanol and ethanol blends are believed to burn "cleaner" than gasoline (i.e., lower in NO_x and hydrocarbon emissions), and have been employed in urban areas with poor air quality. However, because ethanol is a hydrocarbon fuel, its combustion emits CO_2.

In 1998, the United States consumed an estimated 105 trillion Btus of ethanol. Emissions of CO_2 in 1998 due to ethanol fuel burning were estimated to be approximately 2.0 MMTCE (6,744 Gg) (see Table 2-37).

Ethanol production dropped sharply in the middle of 1996 because of short corn supplies and high prices. Plant output began to increase toward the end of the growing season, reaching close to normal levels at the end of the year. However, total 1996 ethanol production fell far short of the 1995 level (EIA 1997). Production in 1998 returned to normal historic levels.

Table 2-37: CO_2 Emissions from Ethanol Consumption

Year	MMTCE	Gg
1990	1.6	5,701
1991	1.2	4,519
1992	1.5	5,492
1993	1.7	6,129
1994	1.8	6,744
1995	2.0	7,230
1996	1.4	5,145
1997	1.8	6,744
1998	2.0	7,300

Methodology

Woody biomass emissions were estimated by converting U.S. consumption data in energy units (17.2 million Btu per short ton) to megagrams (Mg) of dry matter using EIA assumptions. Once consumption data for each sector were converted to megagrams of dry matter, the carbon content of the dry fuel was estimated based on default values of 45 to 50 percent carbon in dry biomass. The amount of carbon released from combustion was estimated using 87 percent for the fraction oxidized (i.e., combustion efficiency). Ethanol consumption data in energy units were also multiplied by a carbon coefficient (18.96 mg C/Btu) to produce carbon emission estimates.

Data Sources

Woody biomass consumption data were provided by EIA (1999) (see Table 2-38). The factor for converting energy units to mass was supplied by EIA (1994). Carbon content and combustion efficiency values were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Table 2-38: Woody Biomass Consumption by Sector (Trillion Btu)

Year	Industrial	Residential/Commercial	Electric Utility
1990	1,948	581	21
1991	1,943	613	21
1992	2,042	645	22
1993	2,084	592	20
1994	2,217	582	20
1995	2,286	641	17

1996	2,370	644	20
1997	2,390	475	19
1998	2,460	468	20

Emissions from ethanol were estimated using consumption data from EIA (1999) (see Table 2-39). The carbon coefficient used was provided by OTA (1991).

Table 2-39: Ethanol Consumption

Year	Trillion Btu
1990	82
1991	65
1992	79
1993	88
1994	97
1995	104
1996	74
1997	97
1998	105

Uncertainty

The combustion efficiency factor used is believed to under estimate the efficiency of wood combustion processes in the United States. The IPCC emission factor has been used because better data are not yet available. Increasing the combustion efficiency would increase emission estimates. In addition, according to EIA (1994) commercial wood energy use is typically not reported because there are no accurate data sources to provide reliable estimates. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

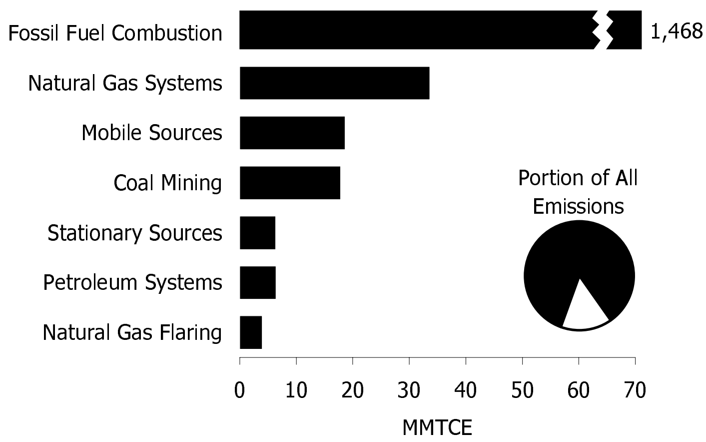

Figure 2-1: 1998 Energy Chapter GHG Sources

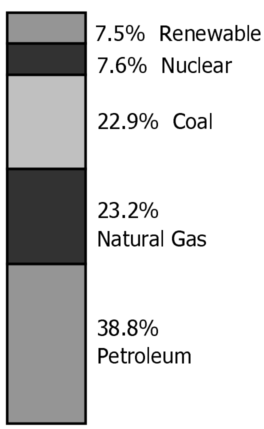

Figure 2-2: 1998 U.S. Energy Consumption by Energy Source
Source: DOE/EIA-0384(99), Annual Energy Review 1998, Table 1.3, July 1999

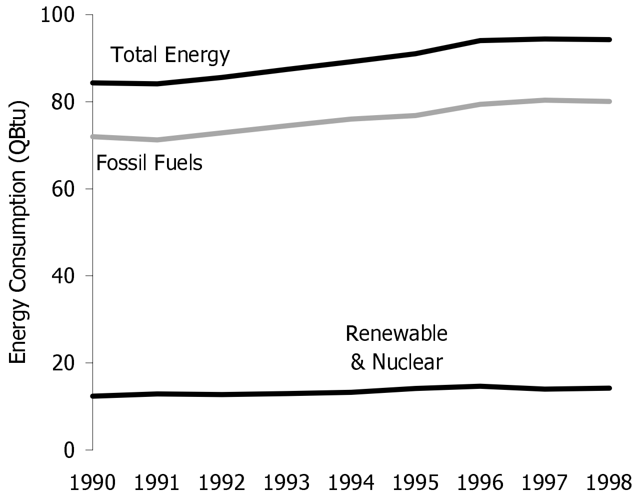

Figure 2-3: U.S. Energy Consumption (Quadrillion Btu)
Note: Expressed as gross Calorific values.
Source: DOE/EIA-0384(97), Annual Energy Review 1998, Table 1.3, July 1999

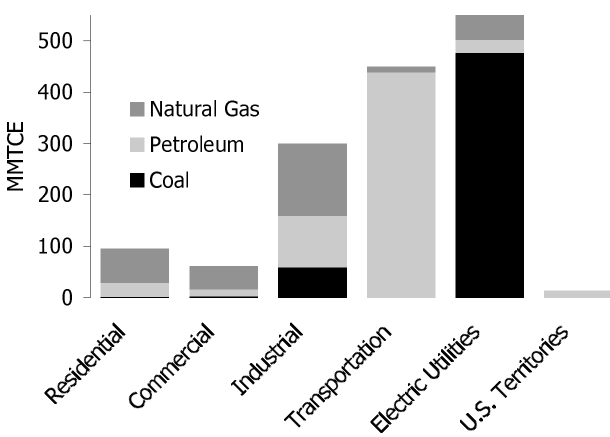

Figure 2-4: 1998 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type
Note: Utilities also include emissions of 0.04 MMTCE from geothermal based electricity generation

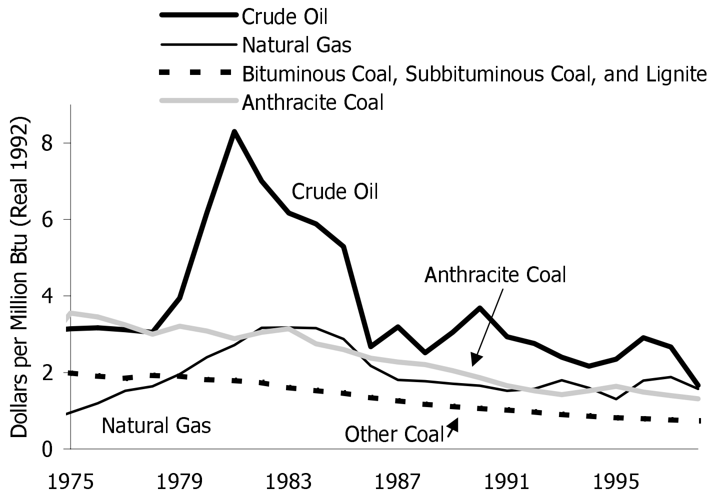

Figure 2-5: Fossil Fuel Production Prices
Source: DOE/EIA-0384(97), Annual Energy Review 1998, July, 1999, Table 3.1

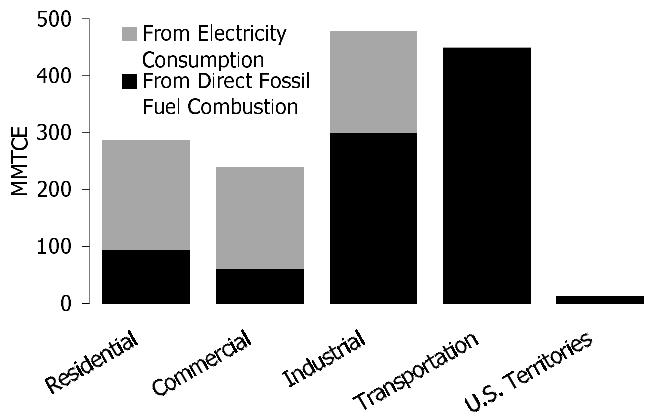

Figure 2-6: 1998 End-Use Sector Emissions of CO_2 from Fossil Fuel Combustion

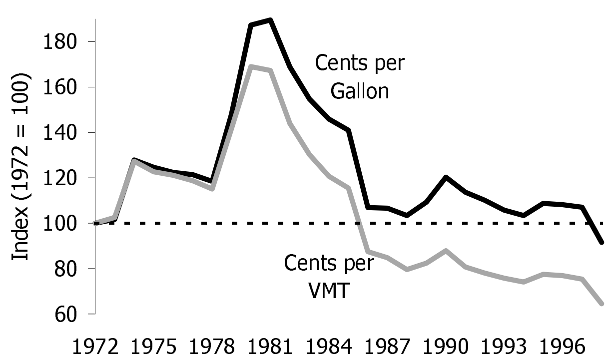

Figure 2-7: Motor Gasoline Retail Prices (Real)
Source for gasoline prices: DOE/EIA-0384(97), Annual Energy Review 1997, July, 1998, Table 5.22
Source for motor vehicle fuel efficiency: DOT/FHWA, Highway Statistics Summary to 1995, Highway Statistics 1996, Highway Statistics 1997

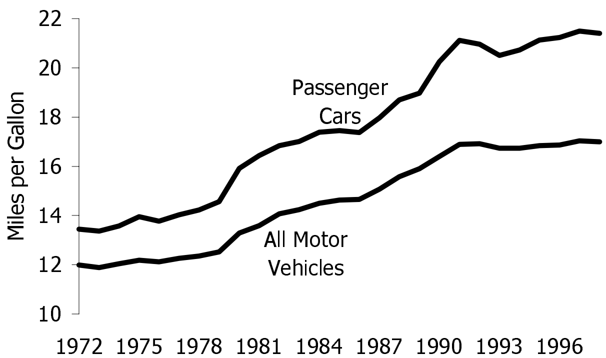

Figure 2-8: Motor Vehicle Fuel Efficiency
Source: DOT/FHWA, Highway Statistics Summary to 1995, Highway Statistics 1996, Highway Statistics 1997

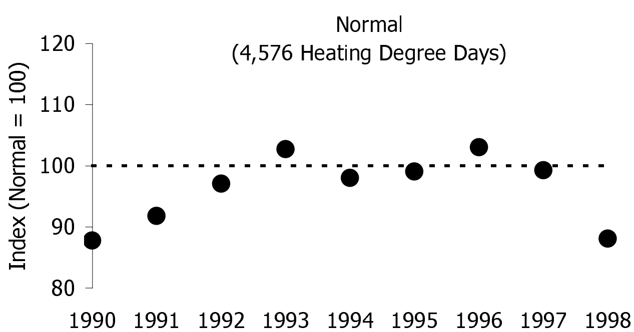

Figure 2-9: Heating Degree Days
Note: Excludes Alaska and Hawaii
Source: DOE/EIA-0384(97), Annual Energy Review 1998, July, 1999, Table 1.7 and 1.8

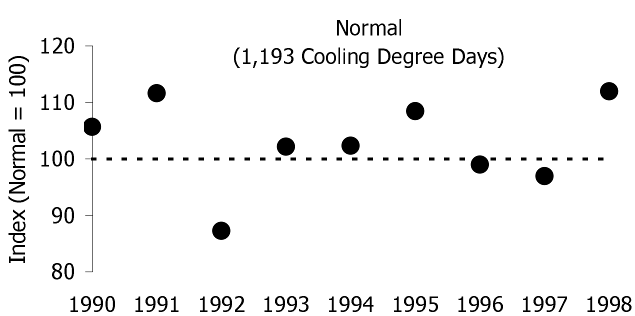

Figure 2-10: Cooling Degree Days
Note: Excludes Alaska and Hawaii
Source: DOE/EIA-0384(97), Annual Energy Review 1998, July, 1999, Table 1.7 and 1.8

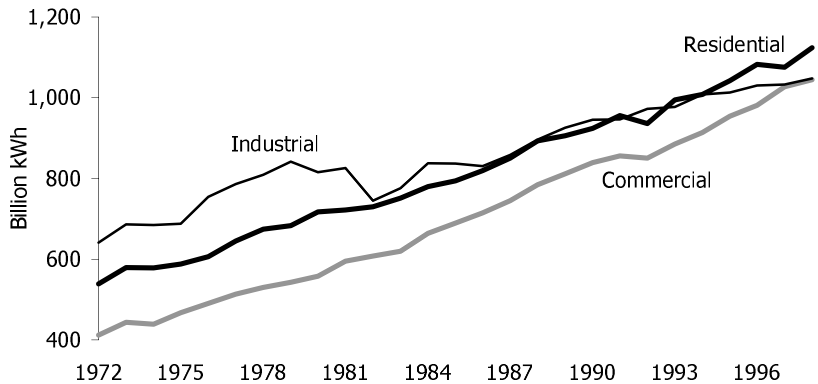

Figure 2-11: Electric Utility Retail Sales by End-Use Sector
Note: The transportation end-use sector consumes minor quanties of electricity.

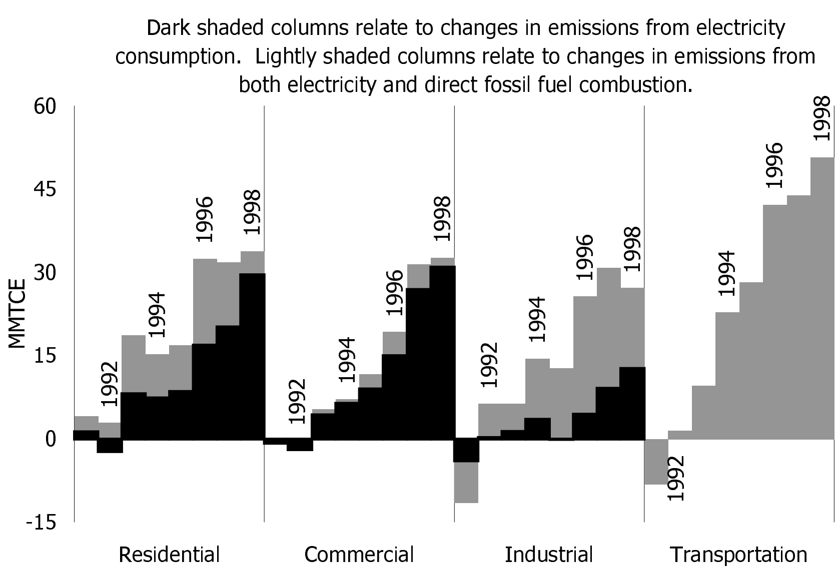

Figure 2-12: Change in CO_2 Emissions from Fossil Fuel Combustion Since 1990 by End-Use Sector

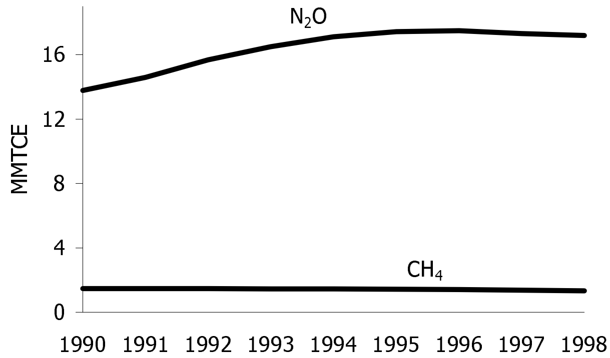

Figure 2-13: Mobile Source CH_4 and N_2O Emissions